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FEBRUARY 2004

Responsible Agencies

U.S. Department of Energy (DOE) – Lead Agency
U.S. Department of Agriculture, Rural Utilities Service – Cooperating Agency

Title

Draft Environmental Impact Statement (EIS) for the Low Emission Boiler System Proof-of-Concept Project; Elkhart, Logan County, Illinois (DOE/EIS-0284)

Contacts

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For information on DOE's NEPA process, contact Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance (EH-42), U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585; telephone 202-586-4600; fax 202-586-7031; or toll-free message at 800-472-2756.

Abstract

This EIS identifies the potential environmental effects of constructing and demonstrating a 91 MW, proof-of-concept coal-fired Low Emission Boiler System (LEBS) for electric power generation. The EIS will be used for decision-making on whether or not to provide cost-shared funding to demonstrate LEBS technologies, which are expected to capture at least 96% of sulfur dioxide (SO_2), decrease oxides of nitrogen (NO_x) by 85%, and remove 99.8% of particulate matter. The LEBS technologies would be integrated into a new power generating station that would be built adjacent to an existing underground coal mine operated by Turris Coal Company in central Illinois, about 2 miles southeast of Elkhart and 17 miles northeast of Springfield. The plant would be owned and operated by Corn Belt Energy Corporation. Current plans target a 24-month construction effort and a 6-month period to demonstrate plant performance before long-term commercial operation of the plant. The plant would burn coal from the adjacent mine and provide electricity to the local power grid. The captured SO_2 would be converted to disposal-grade gypsum, and bottom ash would be marketed for use as roadbed or construction material. Bottom ash that could not be sold and gypsum from flue gas desulfurization would be transported to a permitted site for disposal, either on Turris Coal Company's mine property or on property owned by Corn Belt Energy.

The EIS identifies the environmental effects, including principal effects on air quality and groundwater, from constructing and operating the LEBS plant. The analysis shows that air emissions would not exceed regulatory standards used as indicators of impacts on human health, human welfare, and the environment. Water would be provided by surface water runoff and groundwater from up to six new wells. During normal conditions, surface water would supply the majority of water requirements. Under prolonged dry conditions, groundwater would provide the primary water requirements. Although the analysis indicates that sufficient water would be available for the LEBS plant and that local groundwater supplies would not be adversely affected, uncertainties regarding surface water and groundwater yields, especially under extended drought conditions, would necessitate monitoring both drawdown and water quality. Corrective actions would be initiated if monitoring results indicate that project operation could have an adverse effect. Impacts to other resource areas would be minor. Under the no-action alternative, the LEBS plant would not be built; as a result, environmental conditions at the site would not change and current environmental impacts would remain unchanged from baseline conditions.

Public Participation

Comments on this Draft EIS may be submitted through the end of the comment period on April 16, 2004. All comments will be considered in preparing a Final EIS for the proposed action. Comments received after the comment period will be considered to the extent practicable. All comments should be addressed to Mr. Lloyd Lorenzi at the address provided above.

DOE will conduct a public meeting in Elkhart, IL, to receive comments on the Draft EIS. The date, time, and location of the meeting will be announced in the *Federal Register's* Notice of Availability of the Draft EIS for the Low Emission Boiler System Proof-of-Concept Project and will be publicized in local newspapers and community announcements.

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ACRONYMS AND ABBREVIATIONS

BBP	Babcock Borsig Power
Btu	British thermal unit
CAA	Clean Air Act
CBEC	Corn Belt Energy Corporation
CBEG	Corn Belt Electric Generating Cooperative
CEMS	Continuous Emission Monitoring System
CFR	*Code of Federal Regulations*
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
Cr	creek
dB(A)	decibels as recorded on the A-weighted scale of a standard sound level meter
DNR	Department of Natural Resources
DOE	U.S. Department of Energy
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
FGD	flue gas desulfurization
FR	*Federal Register*
ft	foot or feet
ft^3/s	cubic feet per second
FWS	U.S. Fish and Wildlife Service
g	acceleration due to gravity
gal	gallon
gpd	gallons per day
gpm	gallons per minute
HCl	hydrogen chloride
HF	hydrogen fluoride
IEPA	Illinois Environmental Protection Agency
IHPA	Illinois Historic Preservation Agency
in.	inch
ISCST3	Industrial Source Complex Short-Term (air dispersion model)
ISGS	Illinois State Geological Survey
L	liter
lb	pound
LEBS	Low Emission Boiler System
µg	microgram
µm	micron
m	meter
m^3	cubic meter
mg/L	milligrams per liter
mi	mile(s)
MM	million
mph	miles per hour
MW	megawatt

MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NPDES	National Pollutant Discharge Elimination System
NEPA	National Environmental Policy Act
NO_2	nitrogen dioxide
NO_X	oxides of nitrogen
NOI	Notice of Intent
O_3	ozone
ORNL	Oak Ridge National Laboratory
OSHA	Occupational Safety and Health Administration
Pb	lead
PCB	poly-chlorinated byphenyl(s)
PGA	peak ground acceleration
pH	parts hydrogen (a measure of acidity or hydrogen ion concentration)
PM_{10}	particulate matter less than 10 μm
$PM_{2.5}$	particulate matter less than 2.5 μm
POM	polycyclic organic matter
ppm	parts per million
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
R&D	research and development
RUS	Rural Utilities Service
s	second
SCR	selective catalytic reduction
SO_2	sulfur dioxide
SVOC	semi-volatile organic compound
SZ	seismic zone
UBC	Uniform Building Code
USC	*United States Code*
USDA	U.S. Department of Agriculture
VOC	volatile organic compound

GLOSSARY

The terms and phrases in this Glossary are marked with asterisks at their first appearance in the text to alert the reader of their definitions.

Acid rain (acidic deposition) – Wet (rain, snow, fog) or dry (particle, gas) deposition of acidic substances on the earth's surface following the chemical transformation and transport of SO_2 and NO_x.

Angle of Draw – The angle to the surface established at the edge of mine workings between the vertical and the surface point of zero deformation.

Aquifer – A rock formation that can conduct groundwater and yield significant quantities of groundwater to wells and springs.

Aquitard – A confining bed that retards but does not prevent the flow of water to or from an adjacent aquifer. (A confining bed is a body of impermeable or distinctly less permeable material stratigraphically adjacent to one or more aquifers.)

Blowdown – Water removed from a cooling system to control the buildup of dissolved solids caused by evaporation during the cooling process. Blowdown and evaporative water losses are replaced with "makeup" water.

Bottom ash – Heavy combustion particles that drop out of flue gas in the boiler area or that comprise the fouling deposit residue cleaned off the boiler tubes.

Capacity factor – The percentage of electricity actually generated by a power plant during a year compared with the plant's maximum capacity.

Color – The true color of a liquid sample following removal of turbidity by filtration.

Cooling tower drift – Any water droplets, possibly containing dissolved and suspended solids, that are entrained in air and emitted from a cooling tower.

Copper-oxide sorption system – Equipment used for chemical processing to yield a concentrated SO_2 feedstock for producing salable by-products, such as sulfuric acid or elemental sulfur.

Drawdown – The rate of fall in water level of a natural system, when depletion (i.e., usage, loss, etc.) exceeds replenishment.

Dry scrubbing – Removal of particles, gases, or other impurities from an air or exhaust stream without the use of water.

Electrostatic precipitator – Equipment in which an electrostatic field (i.e., the electric field associated with stationary electrical charges) is used to remove dust or other solids from a gas.

Fabric filter – A device, similar to a large vacuum cleaner bag, that captures particulate matter from flue gas flowing through the bag.

Floodplain – The strip of relatively flat land that is covered with water when an adjacent water body overflows its banks.

Flue gas – The gaseous products of combustion.

Fluvial – Produced by the action of a river.

Fly ash – Fine combustion particles (ash, soot, dust) carried in flue gas.

Formation – The primary unit of formal geological mapping of an area. Formations possess distinctive geologic features and can be combined into "groups" or subdivided into "members."

Glacial drift – Any rock material (such as boulders, gravel, sand, or clay) transported and deposited by a glacier or from the water derived from melting of glacial ice.

Heat exchanger – Equipment used for transferring heat from one fluid to another without allowing the fluids to mix.

Hydraulic conductivity – A measure of the amount of water that can flow through soil or porous rock in a given amount of time.

Hydraulic gradient – A driving force for the flow of groundwater. Groundwater flows from areas of higher energy (or hydraulic head) to areas of lower hydraulic head. The change in hydraulic head per unit distance is the hydraulic gradient. Upgradient areas are areas of higher hydraulic head and downgradient areas are areas of lower hydraulic head. Therefore, groundwater (and any associated contaminants) would flow from upgradient to downgradient areas. These terms are analogous to "upstream" and "downstream" locations for surface water.

Hydrogeologic or Hydrogeology – Term referring to the science that studies subsurface waters and their related geologic features; the term "hydrogeology is often used interchangeably with "geohydrology."

Influence Zone – Surface distance between a point vertically above the edge of the mine workings and the point of no (zero) surface deformation (subsidence).

Lacustrine – Produced by or formed in a lake.

Leaching – The removal, by percolating water, of soluble compounds from soil or other solids. "Leachate" is the term used for the material, including any contaminants, removed from the solids.

Leaky artesian conditions – Conditions where an aquifer is overlain and/or underlain by deposits or confining beds that impede or retard, but do not prevent, the vertical movement of groundwater. An artesian well is drilled to an aquifer depth where downward draining water from above the well creates sufficient pressure to force an upward flow in the well.

Lense – A body of ore or rock thick in the middle and thin at the edges (i.e., shaped like a double convex lense).

Loam – A soil composed of a mixture of clay, silt, sand, and organic matter.

Loess – A homogeneous, non-stratified, unindurated (i.e., loose, soft) soil deposit consisting predominantly of silt, with lesser amounts of very fine sand and/or clay.

Mechanical draft cooling tower – A structure in which circulating water is cooled through partial evaporation by exposure to moving air driven by fans.
Member – A division of a geologic formation differentiated by its physical and geologic characteristics.

Mesic – Refers to an environment that is neither extremely wet nor extremely dry.

Outwash – Glacial drift deposited by melting of snow or ice in front of glacial ice.

Peak ground acceleration – A mathematical measure of the maximum force of an earthquake, in terms of ground motion, that can be related to the ability of structures to withstand earthquake damage.

Perched groundwater – Groundwater separated from an underlying body of groundwater by unsaturated rock.

Permeability – The capacity of a porous rock, soil, or sediment for transmitting a fluid.

Photochemical – A type of chemical reaction or process induced or affected by radiation, chiefly visible or ultraviolet light.

Piezometric surface – The elevation to which water from an aquifer will rise under its full head; in some cases, an imaginary aboveground surface that would coincide with the static level of water in an aquifer.

Plume – A distinct volume or stream of air or water containing a mixture of gaseous, liquid, or solid discharges.

Process water – Generally, all water used in the operation of a facility, such as boiler water and cooling water, with the exclusion of waters used for potable and sanitary services.

Proof-of-concept – A demonstration of technology at a size sufficient to judge the readiness of the technology for commercial application.

Slag – The by-product of firing coal at a temperature above the ash melting point, which is removed from the combustion chamber in molten form and then quenched to produce a glass-like solid (also called a "vitrified ash").

Slurry – The viscous paste typically produced when some solid materials are mixed with water.

Till – Nonsorted, nonstratified sediment carried or deposited by a glacier.

Transmissivity – The rate at which water is transmitted through a unit width of aquifer under a unit gradient.

Turbidity – A measure of the amount of solid particles suspended in water resulting from measurement of the extent to which light traveling through a column of water is scattered by suspended organic and inorganic particles.

Unconsolidated sediment – A sediment that is loosely arranged or unstratified or that contains particles that are not cemented together, or soil material in a loosely aggregated form.

Volatile organic compound – An organic (carbon-containing) compound that readily forms a vapor.

Vitrified ash – See *Slag.*

Wet limestone scrubbing system – Equipment in which a limestone slurry or solution in water is used to remove sulfurous compounds from an air or exhaust stream and in which a by-product of commercial-grade or landfill-grade gypsum can be produced.

Wetland – A term generally applied to seasonally or permanently inundated or saturated land areas. Wetland areas support a prevalence of vegetation typically adapted for life in saturated soil conditions.

Wind rose – A radial graph in which the frequency of wind blowing from each direction is plotted as a bar that extends to the center of the diagram. Wind speeds are denoted by bar widths and shading; the relative frequency of wind speed from each direction is depicted by the length of each section of the bar.

Zero deformation point – The surface point at which vertical movement is 0.01 ft or less.

SUMMARY

This Environmental Impact Statement (EIS) has been prepared by the U.S. Department of Energy (DOE), in compliance with the National Environmental Policy Act of 1969 (NEPA), as amended (42 USC 4321 *et seq.*), to assess the potential environmental effects associated with constructing a coal-fired Low Emission Boiler System (LEBS) to demonstrate improved technologies for electric power generation at the proof-of-concept scale. DOE is the lead agency for the LEBS project. The U.S. Department of Agriculture, Rural Utilities Service, is a cooperating agency in preparing this EIS for the LEBS project. The EIS will be used in making a decision on whether or not to provide cost-shared funding to design, construct, and demonstrate integrated, low-emission power system technologies proposed by a team led by Babcock Borsig Power*, a prime contractor in the LEBS project. The goal of the LEBS project is to provide reliable, economic, highly efficient, and environmentally preferred technologies for pulverized coal-fired power generation.

Description of Proposed Project

The proposed power plant would demonstrate the technologies in a new 91 MW coal-fired power plant to be built adjacent to an existing underground coal mine, which is owned and operated by Turris Coal Company, a member of the project team and supplier of Illinois bituminous coal with 3% sulfur content from the adjacent mine to the power plant. The proposed site is situated in central Illinois, about 2 miles southeast of the village of Elkhart and about 17 miles northeast of Springfield. The power plant would be owned by Corn Belt Energy Corporation (CBEC) and would incorporate the following technologies: (1) a slagging combustor, which is U-shaped to increase the combustion reaction time; (2) low nitrogen oxides (low-NO_x) burners, staged combustion, and coal reburning (using about 10-15% of the coal) for NO_x control during combustion, in combination with a selective catalytic reduction (SCR) post-combustion NO_x control system; (3) a wet limestone scrubbing system for sulfur dioxide (SO_2) capture; and (4) an electrostatic precipitator for particulate removal from the flue gas. The technologies would be expected to capture at least 96% of SO_2 emissions, decrease NO_x emissions by 85%, and remove 99.8% of particulate matter. The technologies proposed for use would achieve SO_2, NO_x, and particulate matter emission levels below 0.15 lb/MM Btu, 0.12 lb/MM Btu, and 0.02 lb/MM Btu, respectively, which are equivalent to or lower than emission control performance objectives specified in the Notice of Intent (61 *FR* 67003) to prepare an EIS for the project.

Based on current plans, construction of the proposed plant would require for about 24 months. Demonstration of technology performance would require a 6-month test period. If the technology demonstration is successful, full-time commercial operation of the power plant would immediately follow. The plant would be designed for a lifetime of 35 years, would burn coal from the adjacent mine, and would provide electricity to the local power grid. Bottom ash from coal combustion would be marketed for commercial applications, such as a road base or construction material. Bottom ash that could not be sold and gypsum produced from the flue gas desulfurization (FGD) scrubber would be transported for disposal at a permitted site either on Turris Coal Company property or at a CBEC disposal site.

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*Note: The North American assets of Babcock Borsig Power have been acquired by Babcock Power, Inc. Readers should note that Babcock Power, Inc., would be the industrial participant for this proposed project. All references in this EIS to Babcock Borsig Power, the Babcock Borsig team, and BBP should be interpreted as referring to Babcock Power, Inc.

Proposed Action and Alternatives

A proposed action by DOE to provide cost-shared funding of approximately $33.5 million (about 23.5% of the total estimated cost of $142.5 million) for design, construction, and operational demonstration of a pulverized coal-fired electric generating facility to demonstrate the integrated operation of low emissions boiler technologies would constitute a major Federal action that could significantly affect the quality of the human environment. Therefore, DOE has prepared this EIS to assess potential impacts of the proposed action and reasonable alternatives on the human and natural environment. The EIS evaluates the proposed action (funding the technology demonstration) and the no-action alternative (not funding the technology demonstration). The only scenario reasonably expected to result as a consequence of the no-action alternative is that the proposed plant would not be built. Other alternatives to the proposed action, such as use of alternative sites or technologies, were considered and found not to be reasonable alternatives requiring detailed analysis under NEPA. The proposed action is DOE's preferred alternative.

Environmental Issues

The principal environmental issues, including impacts on air quality and groundwater, that could result from construction and operation of the proposed power plant have been analyzed in the EIS. The analysis finds that emissions from the proposed plant would not exceed National Ambient Air Quality Standards (NAAQS) or Prevention of Significant Deterioration (PSD) increments. For the latter set of standards, the emissions would always be less than 30% of the allowable degradation. The contributions of emissions from the proposed plant to acidic deposition and to greenhouse gas emissions would be 0.1% and 0.003%, respectively. Air pollutant emissions would not adversely affect workers, members of the public, or ecological resources.

The proposed power plant would obtain water from a 22-acre retention pond that would collect and store field drainage runoff and from up to six new groundwater wells, one of which would be located near the village of Elkhart municipal well. The Farnsworth Group, an engineering, architect, surveyor, and scientist firm from Bloomington, Illinois, was contracted through a cost-shared grant with the Illinois Department of Commerce and Community Affairs to perform a groundwater survey for the power plant. The Pearl/Kansan outwash aquifer at the proposed site would be capable of supporting requirements for groundwater during plant operation. Corn Belt Energy would contract with a qualified firm to monitor both drawdown from pumping the new wells and the water quality of the aquifer. The monitoring data would be used to resolve current uncertainties associated with the potential effects of the new wells on Elkhart's municipal well during periods of extended drought and to provide lead-time for implementing corrective actions if data indicate that adverse effects could result from groundwater withdrawal.

If a permitted new combustion waste disposal area is constructed at the adjacent mine, sufficient disposal capacity would be available to accommodate all solid wastes generated by the proposed power plant during the anticipated 35 year operating lifetime, even if bottom ash could not be sold or used. If the proposed waste disposal area is not constructed, the wastes would undergo disposal at existing facilities on Turris Coal Company's property or would be transported to a permitted disposal site owned by Corn Belt Energy.

Impacts to other resource areas would be minor. Water would be recycled for use. Wastewater from the power plant would discharge to the Turris Mine freshwater pond for use in mine operations. This water would consist primarily of all cooling tower blowdown and would be suitable quality for mine use. All sanitary water from the power plant would be treated in the Turris Mine sewage treatment plant. Discharges to surface waters not located on mine property would occur only during infrequent occasions when appreciable rainfall events exceed existing pumping capacities designed to retain all water on the property. Because off-site surface waters would not be used to meet water supply needs, no effects from surface water withdrawal would result. Flooding at the site would not be anticipated, and floodplain encroachment would not occur. No wetland resources would be impacted. No adverse impacts on terrestrial or aquatic ecosystems would be expected. No historic or archaeological resources are known to exist on the project site. Construction and operation of the power plant would result in minor benefits on socioeconomic factors in the surrounding area, and no disproportionate adverse impacts to minority or low-income populations would be expected. With respect to aesthetic resources, construction of the proposed plant would produce minor short-term visual impacts, but visual characteristics would not differ over the long term from those currently existing at the site. No adverse impacts would be expected with regard to noise, traffic, land use, and human health, including worker safety.

Under the no-action alternative, no construction activities or changes in mine operations would occur. No change in current environmental conditions at the site would result, and impacts for the foreseeable future would remain unchanged from baseline (existing) conditions.

1.0 PURPOSE AND NEED FOR THE PROPOSED ACTION

1.1 INTRODUCTION

This Environmental Impact Statement (EIS) has been prepared by the U.S. Department of Energy (DOE), in compliance with the National Environmental Policy Act of 1969 (NEPA), as amended (42 USC 4321 *et seq.*), to evaluate the potential environmental impacts associated with constructing and demonstrating a coal-fired Low Emission Boiler System (LEBS) for electric power generation at the *proof-of-concept* scale. DOE is the lead agency and the U.S. Department of Agriculture (USDA), Rural Utilities Service (RUS), is a cooperating agency in preparing this EIS for the LEBS project. DOE is considering a proposal to provide cost-shared funding for the LEBS project, and RUS may consider financing a portion of the non-DOE share of the project. Specifically, this EIS will be used in making a decision on whether or not to provide cost-shared funding to design, construct, and demonstrate LEBS technology that was originally proposed to DOE by DB Riley, Inc., a private sector participant in the LEBS project development, and a team comprised of Sargent & Lundy, ThermoPower Corporation, the University of Utah, Southern Illinois University (Carbondale), Reaction Engineering International, AEP Resources, and Zeigler Coal Holding Company (the parent company of Turris Coal Company). Since the project was originally proposed, DB Riley is now doing business as Babcock Borsig Power, and the team of participants is composed of Corn Belt Energy Corporation and the Turris Coal Company. In this EIS, the project team will be referred to as the Babcock Borsig team.

The goal of the LEBS project is to provide reliable, economical, highly efficient, and environmentally preferred technologies for pulverized coal-fired power generation. DOE's role has been to accelerate the development and deployment of technologies that meet LEBS objectives, ensure a better product through competition and involvement of the power industry, and share in the cost of development.

Currently, about 55% of U.S. electricity requirements are met by steam-electric generating stations fired with pulverized coal. The abundance of available reserves in the United States makes coal one of the nation's most important strategic resources for sustaining a secure energy future. Using existing mining technology, recoverable reserves of coal in the United States could support consumption at current levels for nearly 300 years. However, advanced technologies for coal combustion must be developed if coal is to be used for providing an environmentally acceptable and economically competitive source of energy in the 21st century.

Nearly 50% of existing electrical generating capacity in the United States is over 30 years old. Thus, much replacement or refurbishment is anticipated over the next several decades to continue to meet current electricity demand, and new capacity will be needed to keep pace with future increases in demand for electricity. As the most abundant domestic energy source, coal continues to represent an

*Terms or phrases bounded by asterisks are defined in the Glossary, Page xi.

attractive option for future power plants, particularly through advanced technologies that have the potential to dramatically improve environmental performance and efficiency.

Since the early 1970s, DOE and its predecessor organizations have pursued a research and development program for ensuring available and affordable energy supplies while improving environmental quality. Involvement of the Federal government is intended to hasten the development of technology to meet near-term energy and environmental goals, provide technologies that minimize risks to human health and the environment, and encourage continuing research and development directed at ensuring longer-term energy supply. The DOE-supported program includes projects at a sufficiently large scale to allow the power industry to make informed decisions regarding commercialization based on demonstrated technical and economic performance.

As part of this research and development program, DOE's National Energy Technology Laboratory conducted a focused evaluation of the potential for evolving technologies to substantially improve the performance of coal-fired power plants (DOE 1993). This evaluation, performed in 1989 and 1990 at the initial stage of the LEBS development, considered advanced technologies for coal combustion and for control of air emissions and included a review of environmental regulations both in the United States and abroad. Two critical needs for future use of coal were identified: making coal burn cleaner and making coal-fired power plants more efficient. To meet the environmental need, approaches were envisioned that could achieve appreciable reductions in emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and particulate matter. Consultation with personnel representing the power industry and the environmental and research communities helped to identify promising technologies and reasonable environmental objectives for technology development.

For SO_2 reduction, several technologies were identified by DOE as potentially capable of reducing emissions to less than 0.1 lb per million British thermal units (lb/MM Btu) of energy input, which corresponds to a factor of 12 reduction below the New Source Performance Standard of 1.2 lb/MM Btu established by the U.S. Environmental Protection Agency (EPA) for new coal-fired power plants. These technologies included an integrated system for combining *dry scrubbing* with *fabric filters* and desulfurization using a packed bed of copper-oxide beads.

Similarly, several technologies were identified as potentially capable of reducing NO_x emissions to below 0.1 lb/MM Btu of energy input, which is a factor of 5 to 6 reduction from the New Source Performance Standards of 0.5 lb/MM Btu for subbituminous coal and 0.6 lb/MM Btu for bituminous coal and anthracite coal. Included were combustion technologies that provide for staged addition of coal and combustion air and for control of combustion temperature and residence time. *Flue gas* cleanup technologies were identified for post-combustion control.

For particulate matter, advances in *electrostatic precipitators* and fabric filters were identified as promising technologies for reducing emissions below 0.01 lb/MM Btu, which is a threefold improvement over the New Source Performance Standard of 0.03 lb/MM Btu. Nearly all of the improvement would result from reducing emissions of small-sized particles, which are harmful to human health because of their ability to be inhaled into the lungs. Furthermore, because the bulk of hazardous elements and condensed organic matter from coal combustion are deposited on particles, the increased capture of these particles would reduce emissions of potentially toxic substances.

Other benefits of the technologies were identified in addition to these potential improvements in air emission control. Advanced sulfur removal methods could yield marketable by-products. Coal combustion under *slag* production conditions could produce *vitrified ash* inherently resistant to *leaching* at ash disposal sites. Increases in efficiency could result from advances in combustion technology, supercritical steam cycles, and low temperature heat recovery systems. Increased heat recovery from low temperature flue gas could be achieved by using equipment and materials capable of operating near acid dew point temperatures and by further development of low temperature, acid-resistant *heat exchangers*. Electric generating costs would be reduced as a result of these efficiency improvements that, importantly, would also result in reduced air emissions per unit of electricity generated because less coal would be required to produce a given amount of electricity.

To capture the potential benefits of these promising technologies, the National Energy Technology Laboratory defined the LEBS objectives and conducted a competitive solicitation to establish cost-shared activities for industry-conceived LEBS technologies (Kim et al. 1994; Ruth et al. 1997). Target objectives for emissions of SO_2, NO_x, and particulate matter were based on the levels identified previously. These emission objectives were required to be achievable at (1) electricity costs comparable to, and preferably less than, the costs for a new, conventional power plant firing coal in compliance with New Source Performance Standards and (2) energy recovery efficiencies at least as high as the most efficient, modern, conventional coal-fired plant meeting New Source Performance Standards, preferably approaching 42% recovery of the energy content of coal as electrical energy.

The LEBS solicitation was released in December 1990, and three cost-shared contracts were awarded in 1992 to DB Riley (now Babcock Borsig Power (BBP)), ABB-Combustion Engineering, and Babcock & Wilcox. The LEBS contracts included four work phases. Phase I work, which consisted of preliminary design of a conceptual LEBS power plant generating 400 MW[1] of electricity, was completed in August 1994. This power plant size for Phase I was selected to obtain design comparisons at a typical commercial scale. In Phase II, system analysis and subsystem tests were performed at scales ranging from 3 MW to 10 MW. In Phase III, preliminary design of a proof-of-concept facility in the 10 MW to 80 MW size range was performed. At the end of Phase III in 1997, the ABB-Combustion Engineering team informed DOE of its decision not to propose a system for Phase IV demonstration and withdrew from the LEBS technology development effort.

For the Phase IV demonstration, the BBP team proposed to design, construct, and operate a new 91 MW gross electrical output (projected 82 MW net output) facility at Elkhart, Illinois. The Babcock & Wilcox team proposed modification and operation of their existing facility at Alliance, Ohio. In 1997, Congress provided sufficient funding for only a single contract for development of

[1] All electrical generating capacities presented in this EIS are gross, rather than net, electrical capacities, unless otherwise noted; gross capacities include both the electricity provided to customers and the electricity consumed by the electric generating facility during operation.

advanced pulverized coal-fired power plant technology (U.S. House 1998). Subsequent DOE review determined that the Babcock Borsig proposal would provide the most advantageous plant size and technology for achieving LEBS objectives. Thus, DOE selected the technology proposed by Babcock Borsig for continuation into Phase IV.

This EIS addresses the Phase IV work, for which DOE would provide approximately 23.5% of the funds required for constructing and demonstrating LEBS technology based on the Babcock Borsig design at a scale of 91 MW, which is considered to be an appropriate size for verifying the technical performance and economic viability of the technology (Darguzas and Beittel 1997). This EIS considers the environmental consequences of constructing and operating LEBS technology at the site proposed by Babcock Borsig, as well as reasonable alternatives, including the no-action alternative.

1.2 PROPOSED ACTION

The proposed action is for DOE to provide cost-shared funding for the design, construction, and operational demonstration of a new coal-fired LEBS technology for electric power generation at the proof-of-concept scale. Specifically, DOE will decide on providing approximately $33.5 million (about 23.5% of the total cost of approximately $142.5 million) to demonstrate LEBS technology under optional Phase IV of the LEBS program at a new 91 MW coal-fired power plant adjoining Turris Coal Company's existing mine in Elkhart, Illinois.

The BBP team, including Corn Belt Energy Corporation (CBEC) and Turris Coal Company, developed the concept for demonstrating LEBS technology at Elkhart. DOE selected the BBP team for further development of LEBS technology following comparative evaluation of LEBS concepts. Because DOE's role in the Phase IV demonstration would be limited to sharing in the cost for technology demonstration, the decision for DOE is limited to whether or not to fund the project. This level of involvement by DOE limits the alternatives that are available to DOE, that are evaluated in this EIS (Section 2.0), and that would be considered by DOE in making a decision on the proposed action.

1.2.1 Purpose

A major goal of U.S. energy policy is to achieve reliable, affordable, and environmentally sound energy for America's future (NEP 2001). Reliable energy sources would increase America's energy security. Because the abundant domestic reserves of coal provide one of the nation's most important resources for sustaining a secure energy future, DOE has pursued a research and development program that includes advanced systems for using coal in a manner that improves environmental quality. LEBS technology is a key component of this research and development program. The cost-sharing feature of the LEBS technology development effort fits well within DOE's strategy of combining DOE financial support with financial support from private industry for the development of evolving energy technologies (DOE 1998).

Specific objectives have been defined for LEBS development. The Clean Air Act (CAA), including the 1990 amendments, mandates that new and existing coal-fired power plants meet stringent emission levels. To help address this mandate, DOE established requirements that the LEBS development effort demonstrate promising coal utilization technologies that would not only achieve mandated emission levels but would also result in plants operating even more cleanly than required by the CAA while reducing the cost of environmental control. For LEBS development, DOE selected participating teams to demonstrate technology for the combined removal of SO_2, NO_x, and particulate matter, with the goal of achieving emission levels that would be lower than CAA limits while producing power more efficiently and at comparable or less cost. The LEBS development effort would need to generate technical, environmental, and financial data from the design, construction, and operation of facilities at a sufficiently large scale to allow the power industry to assess the potential for commercial application of developed technology.

In summary, the purpose of the LEBS project is to demonstrate promising coal combustion and environmental control technologies that would help the power industry reduce emission levels below mandated levels while reducing costs. Furthermore, a successful demonstration would result in the ability of the U.S. to supply LEBS technology to an expanding world market for advanced coal-fired combustion and pollution control technology.

1.2.2 Need

The need for demonstrating LEBS technology varies among the stakeholders. For DOE, cost-shared funding for the project would address the Congressional mandate in Public Law 99-190 for demonstrating environmentally sound technologies for the utilization of coal. For Babcock Borsig, a successful demonstration would increase opportunities to market LEBS technology for commercial deployment throughout the United States and the world. For Turris Coal Company, the proposed project would become a sizeable long-term consumer of coal from the adjacent mine and would enhance the stability of the company's operations.

From the local community's perspective, the proposed project would provide economic benefits by creating temporary construction jobs and permanent new jobs at the power plant and the coal mine. On a regional basis, the proposed power plant would be the only plant in the State of Illinois' power queue for new transmission capacity anywhere in the area. Electricity generated by the plant could potentially displace electricity supplied by older, less efficient facilities with higher air pollution emission rates, thereby improving the overall air quality of the region.

Although DOE considers that both Corn Belt Energy's needs and the community's interests support the overall value of the project, DOE's primary reason for considering the proposed project is solely to demonstrate innovative, coal-based technology. The cost-share contribution by DOE for the proof-of-concept demonstration would help reduce the risk to the BBP team in developing LEBS technology to the level of maturity needed for decisions on commercialization.

1.2.2.1 DOE's Need

Since the early 1970s, DOE and its predecessor organizations have pursued a broadly based coal research and development (R&D) program for ensuring available and affordable energy supplies while improving environmental quality. This R&D program includes long-term activities that support the development of innovative, unproven concepts for a wide variety of coal technologies. However, before any technology can be seriously considered for commercialization, demonstration at a sufficiently large scale is required to prove operational and economic viability. Due to cost requirements, utilities and other private sector companies generally are reluctant to demonstrate technologies at an unproven scale in the absence of strong economic incentives or legal requirements. The implementation of a technology demonstration program with cost-shared funding from the Federal government has been endorsed by Congress and industry as a mechanism to accelerate the commercialization of innovative technology to meet near-term energy and environmental goals, to reduce risk to an acceptable level through cost-shared funding, and to provide the incentives necessary for continued R&D directed at providing solutions to long-range energy supply problems.

As part of the coal-fired power generation R&D program, the proposed project would meet DOE's need to demonstrate the commercial viability of integrated LEBS technology for providing a reliable, economic, highly efficient, and environmentally preferred approach for pulverized coal-fired power generation. The ability to demonstrate, to prospective domestic and overseas customers, new technology using an operating facility rather than a conceptual or engineering prototype would provide a persuasive inducement to purchase American coal utilization technology. Data obtained on operational characteristics using the integrated pollution control technologies during the demonstration would allow prospective customers to assess the potential of LEBS technologies for commercial application. Successful demonstration of LEBS technologies would enhance prospects for exporting the technology to other nations and may provide an important advantage for the United States in the global competition for new markets. DOE would work closely with the LEBS team to identify plans for technology transfer and for supporting deployment of the technologies in the marketplace.

1.2.2.2 LEBS Team Need

For Turris Coal Company, the proposed generating plant would become a sizeable, long-term user of coal from the adjacent Turris Mine. Because electricity is an appreciable portion of the Mine's coal production costs, stable and low-cost electricity supplied to the local grid by the proposed plant could create economic benefits and energy supply stability for Turris Coal Company.

For Corn Belt Energy Corporation, the LEBS power plant would provide an opportunity to enter the power generation business at a capital cost below that of a comparably sized conventional steam generation facility. In addition to the funding that would be provided by the Department of Energy, additional funds may be available through the State of Illinois' Department of Commerce and Community Affairs. The combination of state and Federal funds would reduce the capital investment required for plant financing. The RUS may also consider financing for a portion of the project, since Corn Belt Energy is eligible for Federal funding as a rural electric utility.

Since terminating membership in Soyland Power Cooperative, Corn Belt Energy has relied almost exclusively on purchased power contracts to meet its member load. Because of price volatility and transmission constraints that limit the importing of power into Illinois, Corn Belt Energy initiated investigations into finding long-term sources of power to obtain a more balanced power supply portfolio of owned generation and purchased power. Corn Belt Energy determined that the proposed LEBS plant adjacent to the Turris Mine could fill a substantial portion of its base-load requirements and has been the prime mover in formulating a corporate structure and soliciting other utilities to participate in the LEBS plant. Corn Belt Energy has also assumed primary responsibility for arranging financing. To construct, own, and operate the plant, Corn Belt Energy formed a new company named Corn Belt Electric Generation Cooperative (CBEG). It is contemplated that the new cooperative will apply to RUS for long-term financing for a portion of the project's capitalization.

On May 1, 2001, Corn Belt Energy became an "all-requirements" customer of Wabash Valley Power Association ("Wabash"), a power supply cooperative headquartered in Indianapolis, Indiana. Effective January 1, 2003, Corn Belt Energy became an all-requirements member of Wabash under a long-term wholesale power contract. Wabash will become a member of CBEG and obtain a share of the LEBS plant's output. In conjunction with its membership in Wabash, Corn Belt Energy will assign its share of the output from the plant to Wabash, and Wabash will incorporate power received from the plant into its power supply resources and supply all of Corn Belt Energy's power supply needs. As a member of Wabash, Corn Belt Energy will realize the economic benefit of the plant's power output as well as other power supply and long-term planning benefits emanating from Wabash's obligations under the wholesale power contract.

Together, Wabash and Corn Belt Energy will take at least 76% of the Turris plant's output. Possible alternatives for the remaining 24% of the output are being evaluated. One possibility is that Wabash will contract for the remaining amount of the plant's output.

The need for the project to serve the power needs of Wabash's members (including Corn Belt Energy) is demonstrated in Table 1.2.1.

Table 1.2.1. Wabash's Total System Needs (MW)

	2003	2005	2007	2009
Capacity Requirement	1,496	1,606	1,727	1,857
Wabash's Owned Generation	159	400	400	400
Wabash's Market Purchases	1,337	1,206	1,327	1,457

Wabash currently relies on purchased power to meet the majority of its requirements. In light of the high dependence on purchased power, Wabash has developed a capacity expansion plan that will produce a less risky power supply portfolio by increasing the amount of owned generation relative to purchased power. Indirect ownership of a share of the plant's output as a member of CBEG is consistent with Wabash's expansion plan.

In addition to Corn Belt Energy, Wabash serves additional members located in Illinois. Thus, as shown in Table 1.2.2, Corn Belt Energy's and Wabash's combined shares of the LEBS plant would partially meet the capacity requirements of Wabash's Illinois load obligation. Operationally, this would minimize Wabash's exposure to transmission constraints that could limit its ability to import power into Illinois to serve its Illinois members.

Table 1.2.2 tabulates Wabash's load and resource balance in Illinois.

Table 1.2.2. Wabash's Illinois Needs (MW)

	2003	2005	2007	2009
Capacity Requirement	194	209	225	241
Wabash's Owned Generation	0.0	0.0	0.0	0.0
Wabash's Shortfall	194	209	225	241

As demonstrated in Table 1.2.2, the LEBS plant would serve existing loads and not be contingent on load growth. The plant would reduce the requirement to purchase power, which over time would probably be more volatile and expensive. Consequently, all of the energy from the plant would be expected to be used by the Wabash system.

Benefits accruing to Wabash and Corn Belt Energy from the project include the following:

- Cost stability through fixing the long-term cost of base load energy at current favorable rates
- Elimination of the volatility associated with power purchases
- Wabash security through contractual rights to an Illinois-based generating unit, thereby reducing its susceptibility to transmission constraints were Wabash to otherwise import power into Illinois to serve its Illinois members

Wabash and Corn Belt Energy have concluded that the proposed LEBS plant is needed and should be a part of the resource mix to serve their Illinois members.

1.3 NATIONAL ENVIRONMENTAL POLICY ACT STRATEGY

DOE determined that providing cost-shared financial support for the LEBS technology demonstration would constitute a major Federal action that could significantly affect the quality of the human environment. Any future decision by RUS to provide financial assistance for the proposed LEBS project would also constitute a major Federal action that could significantly affect the quality of the human environment. DOE, as the lead agency, has thus prepared this EIS for use by decision makers in determining whether or not to provide partial funding for the design, construction, and demonstration of LEBS technology at the proof-of-concept scale. This EIS assesses the potential impacts on the human and natural environment of the proposed action and reasonable alternatives and establishes a basis for the public to provide input and feedback on the proposed action as part of the NEPA process.

This EIS has been prepared in accordance with Section 102(2)(C) of NEPA, as implemented under regulations promulgated by the Council on Environmental Quality (40 CFR Parts 1500-1508) and as provided in DOE regulations for compliance with NEPA (10 CFR Part 1021). The EIS is organized according to Council on Environmental Quality recommendations (40 CFR 1502.10).

A Notice of Intent (NOI) to prepare the EIS and hold public scoping meetings was published by DOE in the *Federal Register* on December 19, 1996 (61 *FR* 67003). The NOI invited comments and suggestions on the proposed scope of the EIS, including environmental issues and alternatives, and invited participation in the NEPA process. The NOI also was printed in the "Legal Notices" section of newspapers in Springfield, Illinois; Richmond, Indiana; and Alliance, Ohio; and was sent to Federal and state agencies for review and comment on the proposed project.

Publication of the NOI initiated the EIS process with a public scoping period (40 CFR 1501.7) for soliciting public input to ensure that (1) significant issues would be identified early and properly studied, (2) issues of minimal significance would not consume excessive time and effort, (3) the EIS would be thorough and balanced, and (4) potential delays that could result from an incomplete or inadequate EIS would be avoided. DOE held scoping meetings in Richmond, Indiana, on January 15, 1997, and in Elkhart, Illinois, on January 16, 1997, near the locations identified as host sites for demonstrating the LEBS technology. The Richmond location was selected by ABB-Combustion Engineering, which has since withdrawn from the LEBS technology development effort. The Elkhart location was selected by DB Riley (now BBP). No scoping meeting was held in Alliance, Ohio, because DOE's internal scoping found no environmental issues of concern associated with the site proposed by Babcock & Wilcox, and because the public identified no concerns when provided with the opportunity to submit comments and suggestions. As noted earlier, the LEBS technology proposed by Babcock & Wilcox was eliminated by DOE from further consideration for the Phase IV demonstration. The public was encouraged to provide oral comments at the scoping meetings and to submit additional comments to DOE by the close of the EIS scoping period on February 3, 1997.

DOE reviewed comments from the meeting in Richmond, Indiana, which were determined to be limited to the proposed project at Richmond. Thus, the comments from the Richmond meeting were not applicable to the Babcock Borsig project and are not discussed in this EIS. No comments were received for the Babcock & Wilcox project. DOE received oral and written responses from two people at the meeting in Elkhart, Illinois. An Illinois state official requested that the EIS address water use and water supplies for the proposed power plant. These issues are discussed fully in the EIS. One member of the public requested that the EIS clearly define and evaluate three options for converting the captured sulfur oxide to a salable product (i.e., ammonium sulfate for fertilizer, sulfuric acid, and elemental sulfur). Although LEBS technology would be capable of implementing the three options, the BBP team selected and proposed a design that uses limestone scrubbing to produce a gypsum product. Therefore, for the purpose of DOE decision-making on the proposed project, the three options for producing a saleable product were not reasonable alternatives and were not considered further in this EIS.

1.4 SCOPE OF THE ENVIRONMENTAL IMPACT STATEMENT

This section summarizes the issues and alternatives considered during preparation of the EIS. The following issues were initially identified by DOE as requiring analysis and assessment in the EIS:

- potential air, surface water, transportation, and noise impacts produced during power plant construction and operation
- pollution prevention and waste management practices, including potential solid waste impacts, during power plant construction and operation
- potential socioeconomic and environmental justice impacts to the surrounding communities as a result of implementing the proposed project
- potential cumulative or long-term impacts from the proposed power plant and other past, present, or reasonably foreseeable future actions
- potential irreversible and irretrievable commitment of resources
- compliance with all applicable Federal, state, and local statutes and regulations
- safety and health of workers and the public during construction and operation of the proposed power plant

DOE used public input obtained during the scoping process (Section 1.3) to add to the list of issues requiring analysis and assessment. As discussions about the proposed project progressed, DOE identified several additional issues that needed to be addressed. Table 1.4.1 lists the composite set of issues identified for consideration in the EIS. Issues are analyzed and discussed in this EIS in accordance with their level of relative importance. The most detailed analyses focus on air quality and groundwater impacts.

Reasonable alternatives to the proposed project (i.e., approaches that are practical or feasible both technically and economically) that were considered initially by DOE as appropriate for meeting DOE's purpose and need, and that were therefore candidates for analysis in this EIS, included:

- alternative size power plants for proof-of-concept testing that would provide the design and performance data needed for scale-up to commercial operation
- alternative technology approaches for meeting the LEBS performance objectives
- alternative sites for demonstrating LEBS technology at the proof-of-concept scale
- no-action alternative, in which funding would not be provided to demonstrate LEBS technology, with the only reasonably foreseeable scenario as a consequence of no action being that the proposed project in Elkhart, Illinois, would not be built

After considering candidate alternatives, DOE determined that the reasonable alternatives to be evaluated in the EIS are the proposed project and the no-action alternative. Alternative sites and alternative technologies were considered by offerors in preparing proposals to the LEBS solicitation and in preparing environmental documentation for projects to be considered for funding. However, offerors did not proposed these alternatives in their responses to the LEBS solicitation. Alternatives that would involve delays in the project or changes in power plant size would not meet the purpose and need for agency action and would not provide obvious advantages for the environmental analysis, and neither option was considered by a LEBS team; therefore, no basis exists for further evaluating these two alternatives.

Table 1.4.1. Issues identified for consideration in the Environmental Impact Statement

Issues identified in the Notice of Intent
Air quality impacts
Surface water impacts
Noise impacts
Transportation impacts
Pollution prevention and waste management practices, including potential solid waste impacts
Socioeconomic and environmental justice impacts to the surrounding communities
Cumulative or long-term impacts from the proposed project and other past, present, or reasonably foreseeable future actions
Irreversible and irretrievable commitment of resources
Compliance with all applicable Federal, state, and local statutes and regulations
Safety and health of workers and the public
Issues identified during public scoping
Options for converting captured sulfur oxide to a salable product
Water use and water supplies for the proposed power plant, including impacts to groundwater
Further issues identified by the U.S. Department of Energy
Aesthetic impacts
Impacts to ecological resources
Impacts to cultural resources
Floodplains and wetlands impacts
Land use impacts

1.5 ASSESSMENT APPROACH AND ASSUMPTIONS

In preparing this EIS, DOE identified and assessed potential environmental impacts of constructing the proposed power plant and testing operations during a demonstration period for DOE. A separate section of the EIS (Section 5.0) addresses potential environmental impacts of commercial operations following successful completion of the demonstration. The potential environmental impacts are assessed for the proposed site and the surrounding area outside the site boundaries, as appropriate, for each resource category considered. Impacts of the proposed power plant during the demonstration period are based primarily on the plant operating characteristics described in Section 2.0 of the EIS, with the major exception that long-term air quality impacts predicted by air dispersion modeling are based on the conservative assumption that the proposed plant would operate at a 100% capacity factor rather than the 85% capacity factor anticipated by Corn Belt Energy Corporation.

2.0 THE PROPOSED ACTION AND ALTERNATIVES

This section discusses the proposed action, the no-action alternative (including scenarios that are reasonably expected to result as a consequence of the no-action alternative), and alternatives dismissed from further consideration.

2.1 PROPOSED ACTION

The proposed action is for DOE to provide cost-shared funding for the design, construction, and demonstration of coal-fired LEBS technology for electric power generation at the proof-of-concept scale. Specifically, DOE will decide whether to provide funding to Babcock Borsig Power (BBP) for demonstrating LEBS technology at a new 91 MW coal-fired power plant.

2.1.1 Location

The site proposed by the BBP team for demonstrating LEBS technology is located in central Illinois, about 17 miles northeast of Springfield and about 2 miles southeast of the town of Elkhart in Elkhart Township, Logan County (Figure 2.1.1). The local terrain is primarily flat to rolling, and the principal topographic feature is Elkhart Hill, which has a maximum elevation of about 200 ft above site grade and is located slightly over 1 mile northwest of the site (Figure 2.1.2). Land use in the rural area surrounding the site is mainly agricultural. Interstate 55, a major thoroughfare between Chicago and St. Louis, passes along the northwest side of Elkhart.

The LEBS power plant would occupy about 5 acres of land adjacent to the existing underground coal mining complex on the 750-acre property owned by Turris Coal Company, a member of the project team. The 300-ft-deep coal mine has operated since 1982 and employs 235 workers to mine about 2 million tons of coal annually. At the current production rate, Turris Coal Company owns sufficient coal reserves for the mine to continue operating for over 30 additional years. Approximately 480 acres of property have been developed for supporting the mining activities, including 265 acres for combustion waste disposal; other features of the developed area include buildings, roads, coal storage piles and silos, coal conveyors, loading facilities for coal trucks, and wastewater ponds. The remaining 270 acres of the site are leased for agricultural use. The project would occupy a section of the property containing a paved road and a mowed grassy field, which currently is designated as the emergency coal storage area for the mine, but which has never been used for coal storage. No mining has occurred beneath a substantial portion of the project site. Major buildings and structures would be sited in areas where subsidence from mining activities would not be likely to occur.

2.1.2 Technology Description

The following technologies proposed for demonstration would be integrated into the design for the power plant: (1) a slagging combustor, which is U-shaped to increase the combustion reaction time; (2) low-NO_x burners, staged combustion, and coal reburning (using about 10-15% of the coal) for

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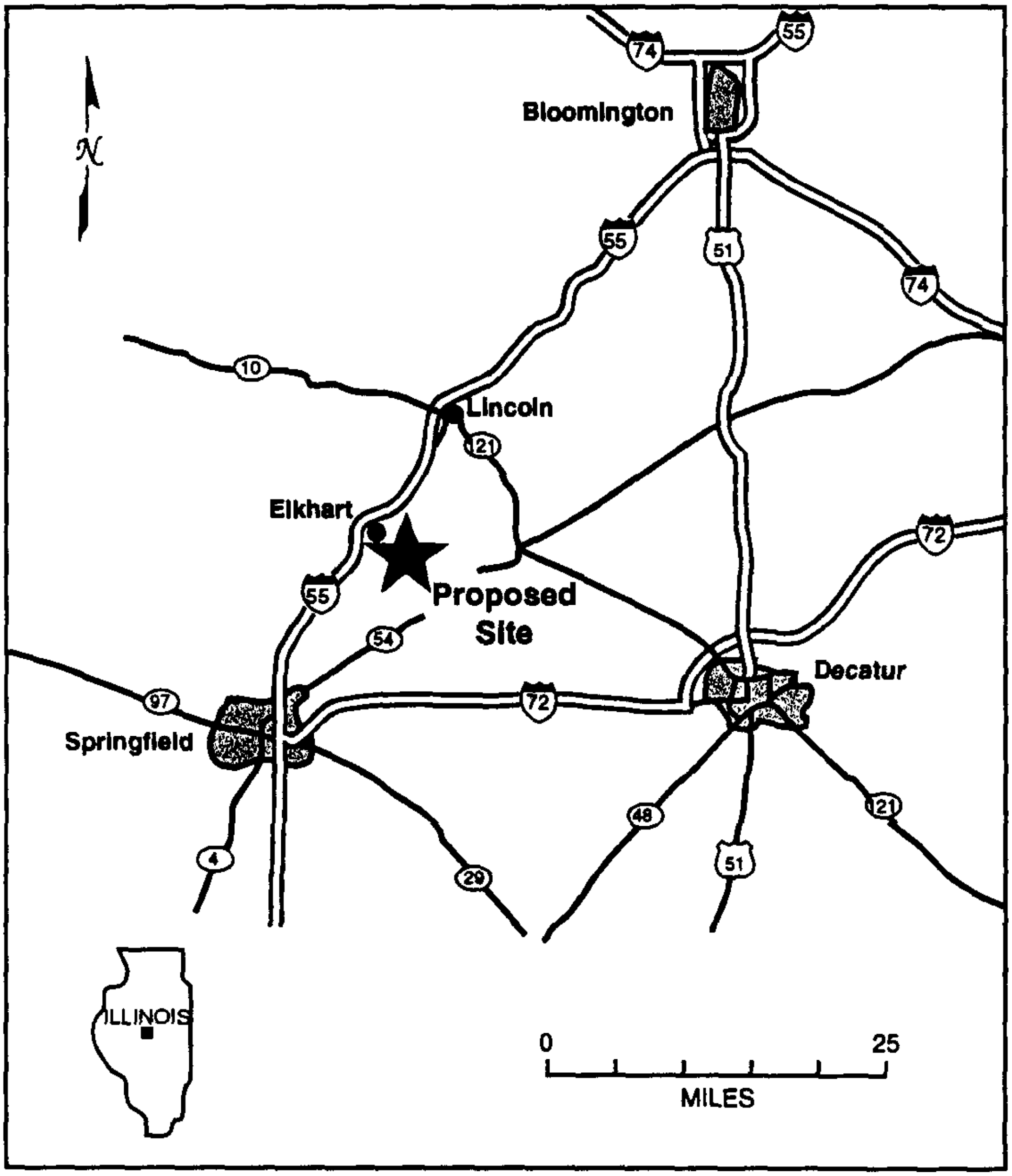

Figure 2.1.1. Regional location map for the proposed LEBS power plant

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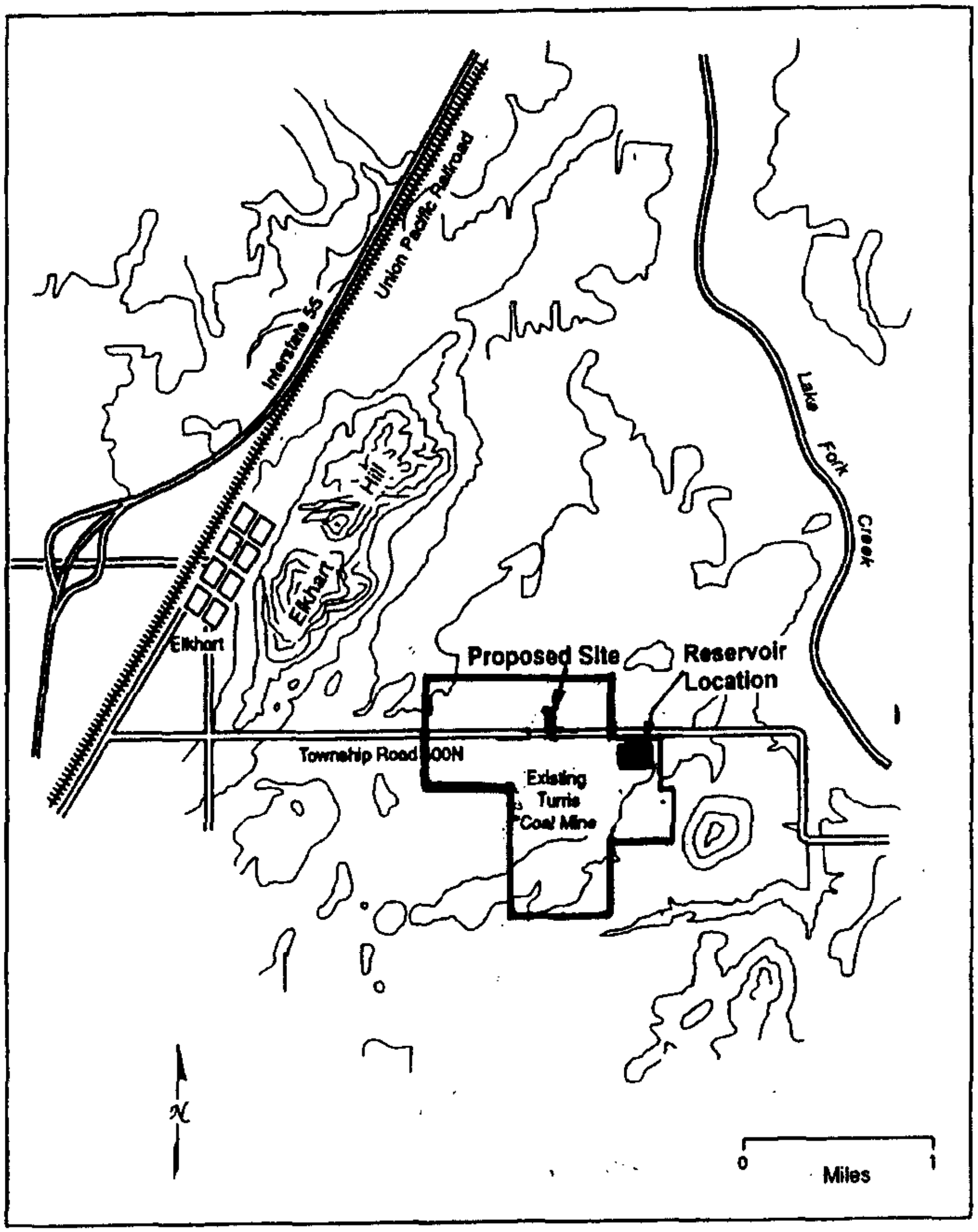

Figure 2.1.2. Proposed site for the LEBS power plant

NO_x control during combustion, in combination with a selective catalytic reduction (SCR) post-combustion NO_x control system; (3) a *wet limestone scrubbing system* for SO_2 capture; and (4) an electrostatic precipitator for particulate removal from the flue gas. These technologies would be expected to capture at least 96% of SO_2 emissions, achieve 85% control of NO_x, and remove 99.8% of particulate matter. Figure 2.1.3 depicts the key components in the integrated system.

Feedwater would be heated in the slagging combustor to produce steam that would drive a steam turbine connected to an electrical generator. The proposed power plant would use a conventional, sub-critical steam cycle that operates at 1,500 psi and 1,000°F. Steam used to drive the turbine would be condensed and recycled to the combustor as feedwater.

The slagging combustor would produce vitrified *bottom ash* from finely ground coal. The *fly ash* from the electrostatic precipitator would be recycled to the combustor to maximize ash discharge as vitrified ash, which would provide a salable by-product used as a road base or construction material. If a market could not be found, the vitrified ash would be mixed with mine wastes for disposal on the mine property or at a permitted CBEC site.

The wet flue gas desulfurization system would use limestone to remove SO_2. The limestone would be ground, slurried, and injected into an absorber where the slurry would react with the SO_2 in the flue gas. Gypsum, the end result of the absorption process, would be filtered, dewatered, and transported for disposal at an existing disposal site on the mine property or at a permitted CBEC site. Chlorides introduced into the facility in the coal and mine water would be mixed with gypsum before disposal.

2.1.3 Project Description

The project proposed by Babcock Borsig would incorporate the LEBS technology described in Section 2.1.2 into the new 91 MW coal-fired power plant. A conceptual layout of the proposed power plant is shown in Figure 2.1.4, and a diagram of the plant is displayed in Figure 2.1.5. The demonstration would be expected to generate sufficient data from design, construction, and operation to allow private industry to assess the potential of LEBS technology for commercial application.

The power plant would be fueled with bituminous coal from the adjacent, existing underground coal mine owned by Turris Coal Company. Currently, the Turris Coal Company uses an existing coal silo, which is depicted on Figures 2.1.4 and 2.1.5, to store mined coal that has been washed and readied for market. A conveyor is used to transport coal from the storage silo to a truck loading facility. Under the proposed project, the truck loading facility would be modified to provide direct feeding of coal onto a new conveyor that would weigh and transport coal to the new power plant.

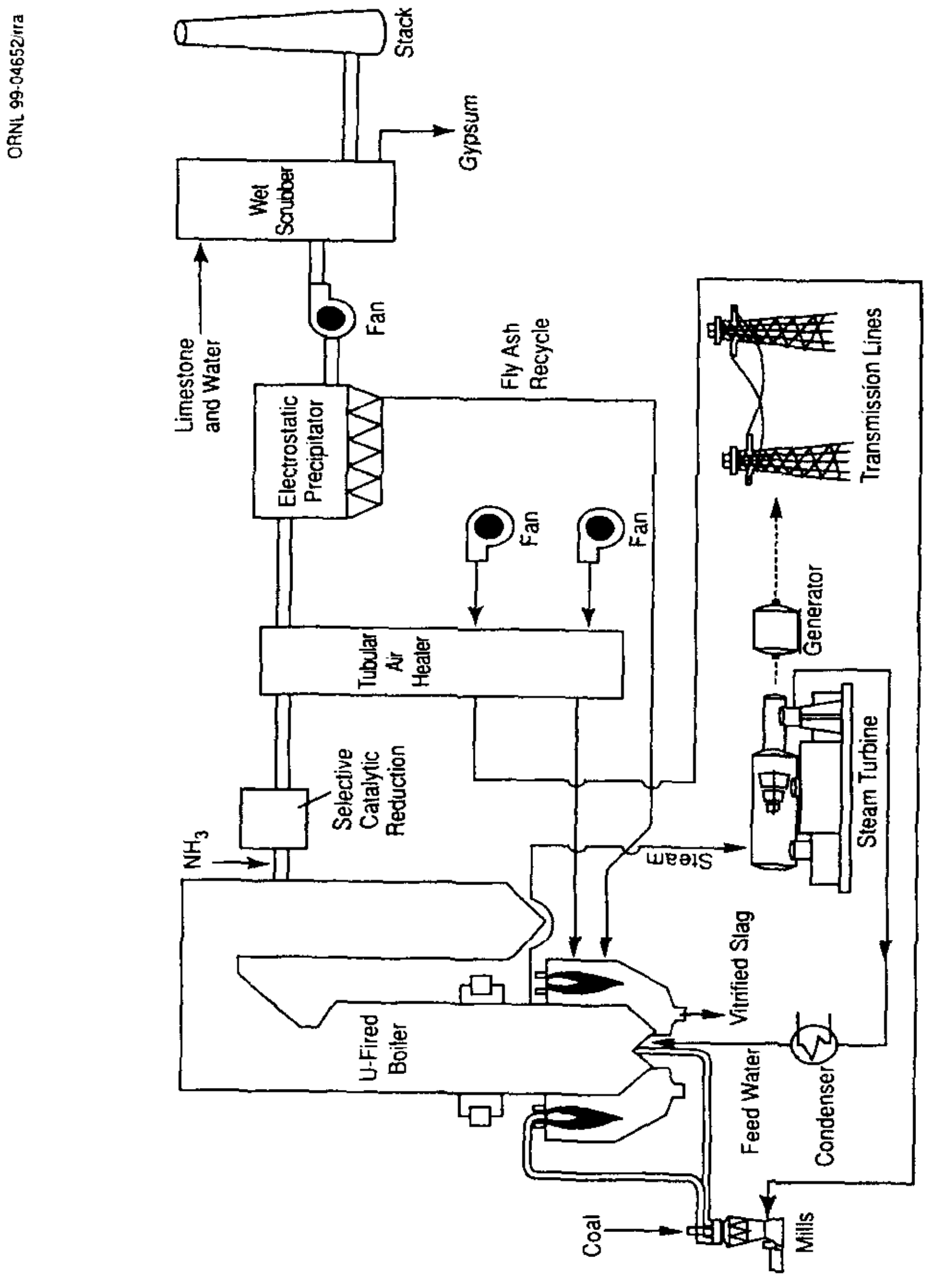

Figure 2.1.3. Flow diagram illustrating key components of the LEBS technology

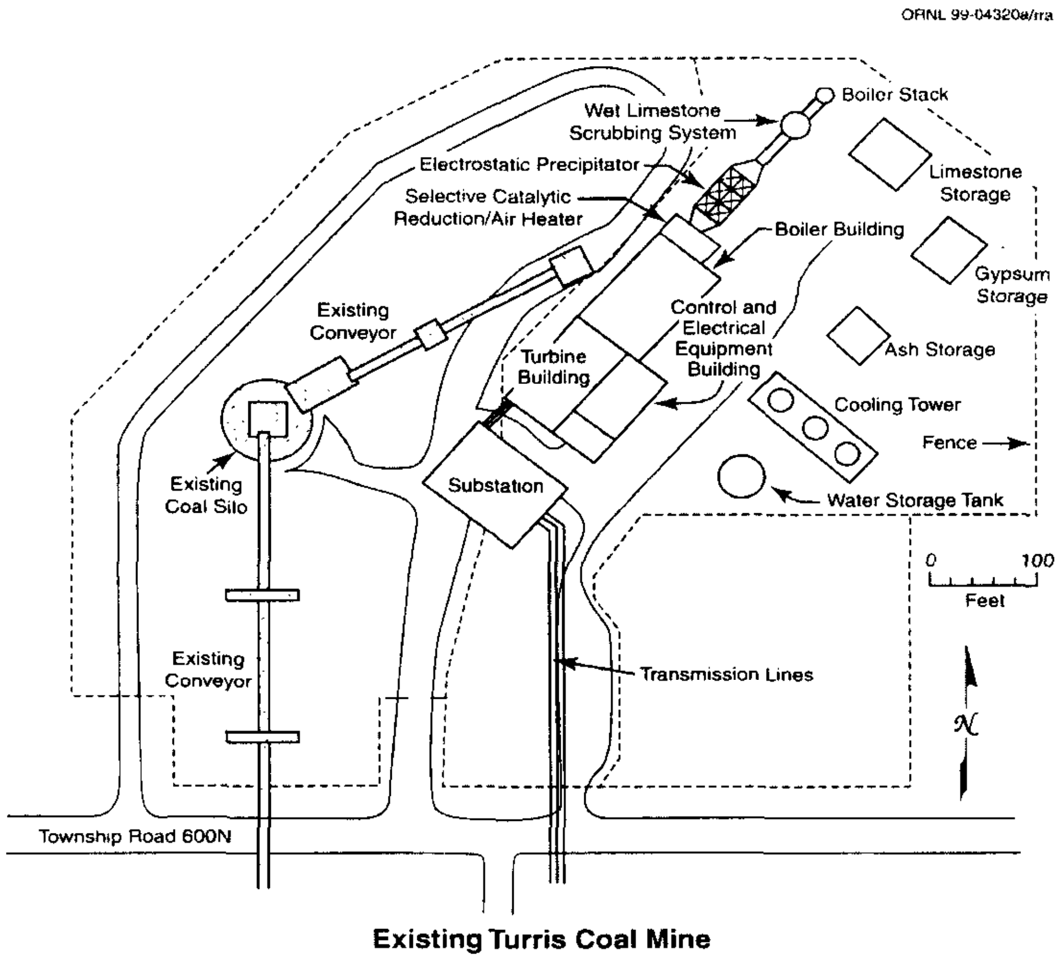

Figure 2.1.4. Layout of the proposed LEBS power plant

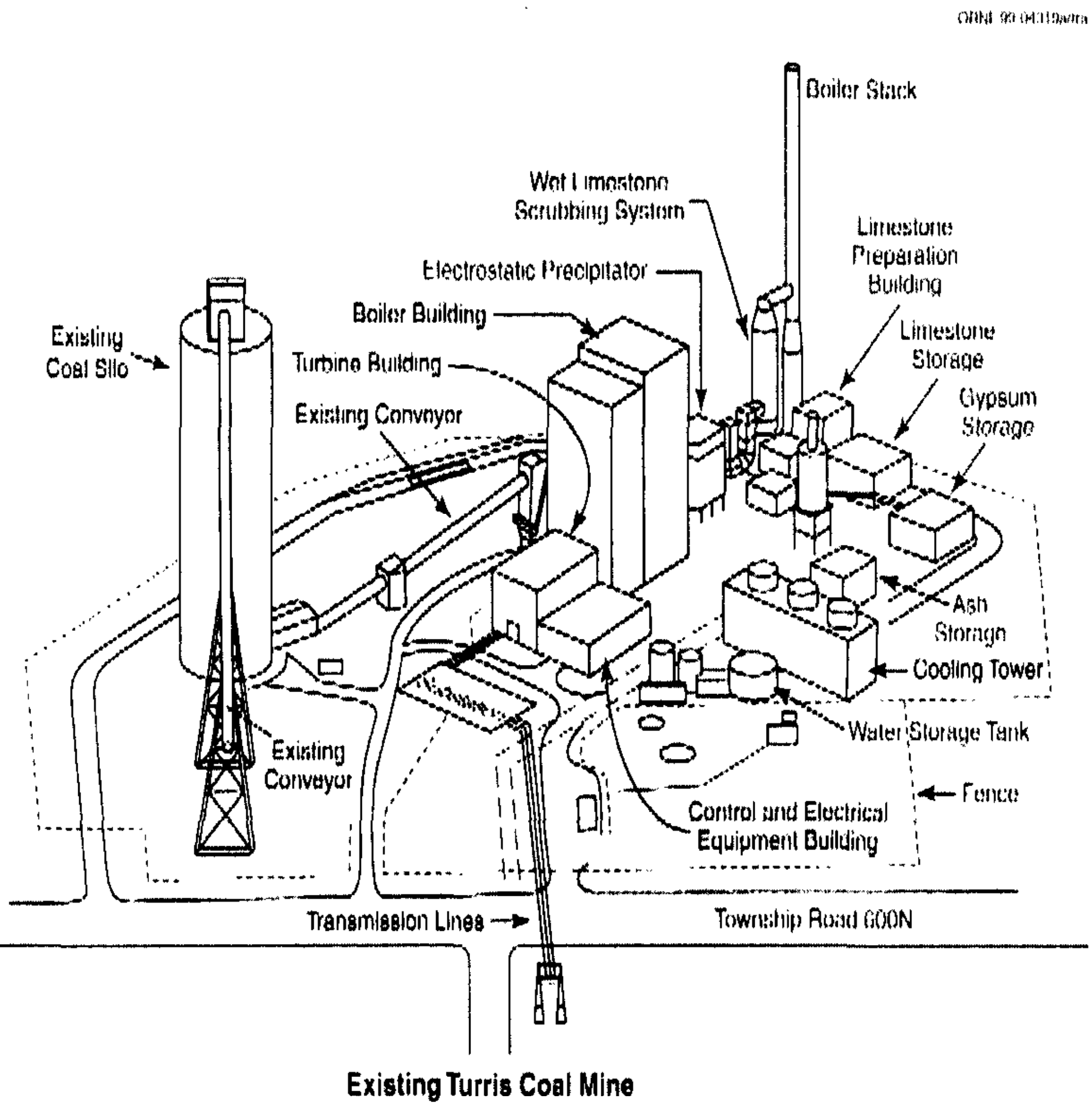

Figure 2.1.5. Diagram of the proposed LEBS power plant

Coal from the Turris Mine was used for combustion tests in a small U-shaped slagging combustor at a Babcock Borsig research facility; testing indicated that ash from the slagging combustor would not be hazardous (Zecco 1997). Electricity generated by the power plant would be provided to the local power grid through an existing substation. To more precisely quantify the amount of electricity to be generated, the LEBS facility would produce a net electrical output of 82 MW and a gross operating output of 91.1 MW. The internal power requirement for the plant would be about 9 MW and the balance (82 MW) would be supplied to the local power grid.

A new *mechanical-draft cooling tower* would be used to discharge heat to the atmosphere. Water in this secondary cycle would pass through the condenser to absorb heat from the steam coming from the boiler and turbine in the primary cycle. The cooled steam would condense into water, which then would be recycled to the boiler. The heated water in the secondary cycle would then be pumped to the cooling tower where a small percentage would evaporate, thus cooling the remaining water. Field drainage runoff and groundwater wells would replenish the water lost by evaporation. The water then would be returned to the condenser to repeat the cycle.

Permits and other regulatory compliance issues for the proposed project are discussed in Section 7.

2.1.4 Construction Plans

As shown in Figures 2.1.4 and 2.1.5, key structures that would be built for the proposed power plant include a turbine building; a boiler building; housing for the wet limestone scrubbing system and electrostatic precipitator; a boiler stack; a coal conveyor to connect the power plant with an existing conveyor system from the coal silo to a truck loading facility; a building for electrical equipment and controls; on-site electric transmission lines and towers that would traverse Township Road 600N to connect a new transformer for the power plant with an existing substation on the mine property; a cooling tower; water storage tanks; and storage structures for fly ash, bottom ash, and gypsum. Because the power plant would occupy a nearly level site containing a paved road and a mowed field, minimal site clearing and grading would be required. Nearby land uses would not be affected by plant construction activities.

Under current plans, the construction period for the proposed plant would extend over 24 months. On average, approximately 100 construction workers would be on the project site during the construction period. The peak number of construction workers on the site would be about 180.

2.1.5 Operational Plans

Demonstration of the proposed LEBS technology, including performance testing and monitoring, would be conducted for approximately 4,000 hours during a 6-month period. Approximately 25 new employees would be required to operate and maintain the power plant. If the demonstration is successful, full-time commercial operation of the plant would follow immediately. During commercial operation, the plant would be used as a baseload power plant operating 24 hours per day, 7 days per week, at an 85% annual *capacity factor*. The power plant would be designed for a lifetime of 35 years.

2.1.6 Resource Requirements

Operating characteristics, including resource requirements, during demonstration of the proposed technology are presented in Table 2.1.1.

2.1.6.1 Land Area Requirements

Land requirements for construction include areas for equipment/material laydown, temporary storage, assembly of site-fabricated components, construction equipment access, and temporary facilities to be used by the construction work force (i.e., offices and sanitary facilities). The 750 acre property owned by Turris Coal Company would easily accommodate these land requirements. The proposed facility would occupy about 5 acres of the property. A 15 ft deep, 22 acre retention pond for collecting field drainage runoff would be located east of the project site and south of Township Road 600N on Turris Coal Company property (Figure 2.1.2). The retention pond would be established in consultation with the Illinois Department of Natural Resources; the pond may be located on Turris property farther south from the site depicted on Figure 2.1.2.

2.1.6.2 Water Requirements

During construction, groundwater obtained from wells would be used for concrete formulation, equipment washdown, general cleaning, and dust suppression. Potable water would be provided by the construction contractor from off-site sources or the new wells. During operation, total water use at the proposed plant would be about 1,195 gallons per minute (gpm) (1.72 million gallons per day (MM gpd)), with about 75% used to replace water evaporated in the plant's cooling tower. The plant's water needs would be provided primarily by field drainage runoff from a 2,540 acre drainage area (Figure 3.3.2), which would feed the new 22 acre retention pond sized to hold about 50 days supply of water, and up to six new groundwater wells. One proposed well would be located in the northwest corner of Turris Coal Company's property in the vicinity of the water supply well for the village of Elkhart, and the other five wells would be located approximately two miles to the east.

The field drainage runoff would be piped to the retention pond, which would be constructed on the eastern side of Turris property (Figure 2.1.2). The retention pond fed by the field tile drains would function to simplify water management and allow the proposed plant to continue operations without substantial water impacts during a major drought period. Flow in the field tile drains would fluctuate seasonally, with a maximum measured flow of 2.0 MM gpd. Due to seasonal variations in rainfall, and during periods of drought, the field tile drains may not be sufficient to maintain adequate storage in the retention pond for servicing the needs of the power plant. During these periods, groundwater wells would provide the primary source of make-up water to the cooling tower. Well water, which could contain low concentrations of impurities, such as carbonates or sulfates of lime and magnesia and oxides of iron, aluminum, and silicon that result in scale formation or corrosion in boilers, would be treated to produce demineralized water that would provide the source of water to the plant's boilers. Except during some summer months and during droughts, water flows through the field drainage area and into Lake Fork Creek. The proposed plant would capture and use the water available from this source.

Table 2.1.1. Operating characteristics of the proposed LEBS power plant

Operating characteristic	Quantity
Capacity, MW	91[a]
Capacity factor[b], %	85
Power production, MWh/year	677,600
Size of power plant site, acres	5[h]
Coal consumption, tons/hour	47
Water use, gpm	
Cooling tower evaporation and drift loss	904
Cooling tower makeup	1,084
Boiler feedwater[c]	29
Boiler evaporation	10
Water softening sludge	55
Sanitary use	3
Slag evaporation and by-product (waste) loss	16
FGD evaporation and by-product (waste) loss	120
Boiler feedwater treatment wastewater	16
Anhydrous ammonia (for NO_x control), lb/hour	260
Limestone (for SO_2 capture), lb/hour	10,729
Air emissions, lb/hour	
Sulfur dioxide, SO_2	238[i]
Nitrogen oxides, NO_x	125[i]
Particulate matter, PM	24[i]
Carbon monoxide, CO	188[i]
Volatile organic compounds, VOCs	29[i]
Carbon dioxide, CO_2	208,000
Effluents, gpm	
Cooling tower blowdown[d]	180
Water treatment waste (softener regenerate waste)	55
Sanitary waste[e]	3
Slag waste and FGD waste	43
Solid waste, lb/hour	
Vitrified ash (slag)[f]	9,400
Gypsum[g]	24,118

[a]*The LEBS facility would achieve a guaranteed net electrical output to the local grid of 82 MW from a gross* operating output of 91 MW. The internal power requirement for the facility would be about 9 MW.

[b]Capacity factor is the ratio of the energy output during a specified period of time to the energy that would be produced if the equipment had operated with maximum power production during that period.

[c]Supplied by demineralized well water.

[d]This nonpotable water would be discharged to the mine's coal washing, FGD, and slag handling water supply.

[e]Sanitary waste would be treated using the existing sewage treatment plant.

[f]To be marketed for sale as road base or construction material, or for disposal at a permitted site.

[g]*For disposal at a permitted site.*

[h]An additional 22 acres would be used for a water retention pond, thus increasing total land usage to 27 acres.

[i]The air permit issued by the Illinois Division of Air Pollution (Appendix D) contains permissible emission rates lower than used in the EIS – SO_2 by 45% to 133 lb/hr, NO_x by 13% to 109lb/hr, PM by 25% to 18 lb/hr, CO by 4% to 181 lb/hr, and VOCs by 80% to 6 lb/hr. The air quality analysis in the EIS thus overestimates impacts and provides a more conservative analysis than would be experienced based on the emission rates in the approved permit.

About 904 gpm of water would be used to replace water lost by cooling tower evaporation and *cooling tower drift*. Approximately 29 gpm would be used as boiler make-up to replace boiler *blowdown* and drift losses. Wastewater from boiler feedwater treatment (16 gpm), equipment maintenance (2 gpm), and cooling tower blowdown (118 gpm) would be used as make-up water (136 gpm) for the wet limestone scrubbing system and the slag handling system. A portion of this water would be incorporated into by-product materials that would either be marketed or transported for disposal as waste at off-site facilities. About 62 gpm of cooling tower blowdown would be discharged to the Turris Mine freshwater pond, which is used as a source of water for washing coal. About 3 gpm of potable water would be required for sanitary use at the power plant.

Figure 2.1.6 presents a water flow diagram depicting water requirements and discharges associated with the proposed plant in relation to the existing mine. The figure provides water flow data representing normal operations, whereby 100% of the cooling tower make-up would be provided from the field-tile-drain-supplied retention pond. Two additional operating scenarios exist for the cooling tower – make-up water could be supplied totally from the groundwater wells, or both wells and the retention pond could be used to provide the make-up water.

Although Figure 2.1.6 indicates a direct connection between the wells and the retention pond, a more cost-effective approach may be to connect the water supply line from the wells directly to the water conditioning unit (i.e., lime softener). This approach would eliminate the cost of installing pipe and flow controls for transporting water from wells to the retention pond and would reduce evaporation loss at the retention pond, by providing water on demand directly to the lime softener from the wells rather than from the retention pond. The decision between these approaches would not affect the water balances and would be considered during final design of the power plant.

2.1.6.3 Fuel Requirements

The proposed combustor would be fueled with bituminous coal from the adjacent, existing underground coal mine. The heating value of the coal expected to be received at the power plant site would be 10,450 Btu/lb, the sulfur content would be 3%, the ash content would be 9.5%, and the moisture content would be 17.5% (Table 2.1.2). At full load conditions, the combustor would consume coal at a rate of 47 tons per hour. Because of periodic down time, approximately 110,000 tons of coal would be burned during the 6-month demonstration. Based on an 85% annual capacity factor, average annual coal consumption would be about 350,000 tons during commercial operation. The mine can easily accommodate an approximately 17% increase in mining from the current level of 2 million tons of coal annually to supply the needs of the power plant. Increased production from the mine, assuming that coal deliveries to other customers would not change, would decrease the useful life of Turris Coal Company's existing reserves by 17%. Additional coal reserves are available to Turris Coal Company for future acquisition, if needed.

Figure 2.1.6. Water flow diagram for the proposed power plant in relation to the existing Turris Mine

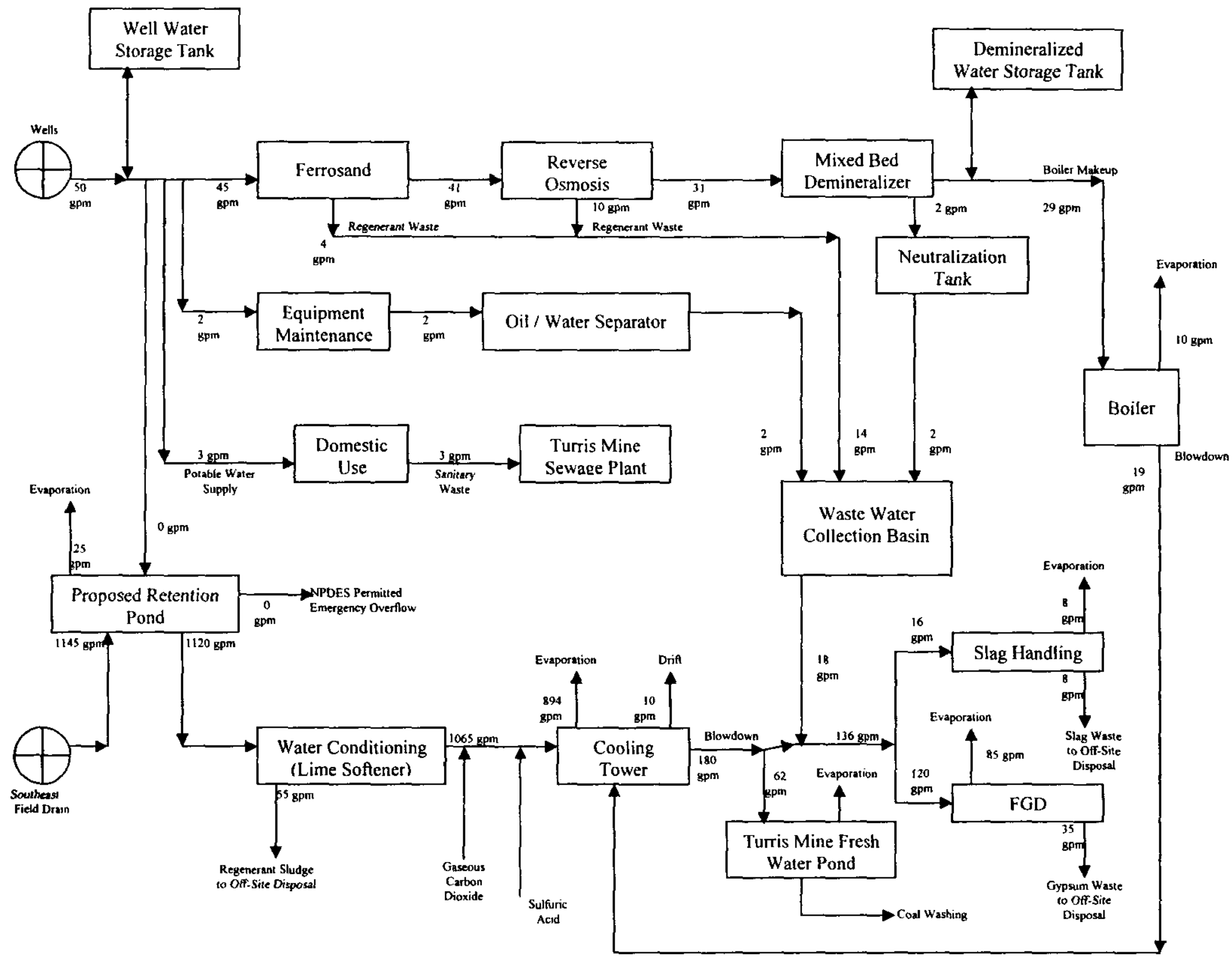

Table 2.1.2. Composition of coal from the Turris Mine, as expected to be received by the proposed power plant

Characteristic	Typical value
Heating value, Btu/lb	10,450
Analysis, percent by weight	
Moisture	17.5
Carbon	57
Hydrogen	4
Nitrogen	1
Sulfur	3
Ash	9.5
Oxygen	7
Chlorine	0.1
Total	100[a]

[a]Rounded to 100.

Source: Turris Coal Company.

The typical composition of the ash produced from Turris Mine coal is shown in Table 2.1.3.

Table 2.1.3. Typical composition of ash produced from Turris Mine coal

Constituent	Weight Percent
SiO_2	55.27
Al_2O_3	15.18
TiO_2	1.00
Fe_2O_3	17.18
CaO	3.61
MgO	0.61
K_2O	1.62
Na_2O	1.32
SO_3	4.23
Total	100

2.1.6.4 Construction and Other Materials

Locally obtained construction materials would include crushed stone, sand, and lumber for the proposed power plant and temporary structures such as enclosures, forming, and scaffolding. About 10,730 lb/hour of limestone would be used for SO_2 capture in the wet flue gas desulfurization system. The limestone would be delivered by truck and stored in a concrete storage structure. The limestone would be wet-ground and slurried with water before being used in the absorber of the flue gas desulfurization system. About 260 lb/hour of anhydrous ammonia would be used for NO_x control in the post-combustion NO_x control system. The anhydrous ammonia would be transported by truck to the site and stored as a liquid in a storage tank.

2.1.7 Outputs, Discharges, and Wastes

Table 2.1.1 includes a summary of discharges and wastes from the proposed power plant.

2.1.7.1 Air Emissions

During the demonstration period, air emissions from the combustor would include 238 lb/hour of SO_2, 125 lb/hour of NO_x, 24 lb/hour of particulate matter, 188 lb/hour of carbon monoxide (CO), and 29 lb/hour of *volatile organic compounds* (VOCs). Trace emissions of other pollutants, including beryllium, sulfuric acid mist, mercury, hydrochloric acid, benzene, arsenic, and various heavy metals, would be produced. The Illinois Environmental Protection Agency (IEPA) has classified the proposed facility as a major source of hazardous air pollutant (HAP) emissions because the potential HAP emissions from the plant would exceed 10 tons per year for an individual HAP – hydrogen chloride (Appendix D). The combustor also would create about 208,000 lb/hour of CO_2, which is not considered an air pollutant but which is a contributor to the atmospheric greenhouse effect that is suspected to cause global warming and climate change (IPCC 1992).

2.1.7.2 Liquid Discharges

About 62 gpm of blowdown from the power plant's cooling tower would be discharged to the existing freshwater pond at the Turris Mine. The slag handling and FGD systems would discharge an estimated 8 gpm and 35 gpm, respectively, of potential waste materials for off-site disposal. In addition, up to 55 gpm of sludge resulting from the conditioning of water use in the cooling tower would be discharged for off-site disposal. Sanitary wastes (approximately 3 gpm) would be treated using the existing sewage treatment plant at the Turris Mine. No other liquid discharges would be anticipated during normal operations. During extreme precipitation events, the field drainage retention pond could fill and exceed the designed storage capacity. Design of the retention pond would include a spillway that would discharge water to Lake Fork Creek if the capacity of the retention pond should be exceeded.

2.1.7.3 Solid Wastes

The proposed plant would generate about 9,400 lb/hour of coal combustion ash in the form of vitrified ash (slag). Fly ash collected in the electrostatic precipitator would be recirculated to the combustor, which would convert the fly ash into additional inert, non-leachable vitrified ash. The wet flue gas desulfurization system would generate approximately 24,000 lb/hour of gypsum.

The slag produced from combustion of coal would be sold for use as a road base or construction material. If a market could not be established, the slag and the gypsum produced by the wet flue gas desulfurization system would be transported for disposal at the mine's on-site disposal facility or at a permitted CBEC site. As discussed in Section 6.0, Turris Coal Company has obtained a permit to construct a new 72 acre, coal combustion waste disposal facility that would provide ample disposal capacity for combustion wastes from existing customers and from the LEBS demonstration. Construction of this waste disposal facility would depend on future demand.

No hazardous wastes would be generated from operation of the proposed power plant. All ash and gypsum from the facility would be nonhazardous. Occasionally, the hoppers used to collect fly ash prior to reinjection into the combustor would need to be cleaned. On these occasions, the ash removed from the hoppers would be analyzed to determine the proper method for disposal. While the Turris Coal Company's slurry pond is already permitted to accept such waste, material cleaned from the hoppers may be transported for off-site disposal in a permitted landfill.

The gypsum product would also be tested prior to transport to any off-site landfill. Any other wastes generated by the proposed plant would be similar to wastes generated at modern conventional power plants, which typically do not produce hazardous wastes.

2.2 ALTERNATIVES

Section 102(2)(C) of NEPA requires an EIS to include a discussion of reasonable alternatives to the proposed action. The term "reasonable alternatives" is not self-defining, but rather must be determined within the context of the proposed action. The goals of the Federal action establish the limits of reasonable alternatives. For LEBS technology development, DOE established the goal of demonstrating promising coal technologies that would operate efficiently and decrease the cost of electricity while reducing emissions of SO_2, NO_x, and particulate matter below mandated levels. DOE's purpose in proposing to proceed with Phase IV of the LEBS project is to demonstrate the technology's viability in achieving DOE's goal at a commercial scale. Reasonable alternatives to the proposed action must be capable of meeting this purpose.

DOE is pursuing the LEBS goal by considering partial financial support for the project owned and controlled by the Babcock Borsig team. This ownership situation places DOE in a much more limited role than if the Federal government was the owner and controller of the project. If DOE was the owner, DOE would be responsible for a comprehensive review of reasonable alternatives for siting a plant to demonstrate LEBS technology. However, in dealing with a project proposed by the private sector, the scope of alternatives is necessarily more restricted. In such cases, DOE must give substantial weight to the needs of the proposer in establishing reasonable alternatives for achieving DOE's goals.

Based on the foregoing discussion, the only reasonable alternative to the proposed action is the no-action alternative (including scenarios reasonably expected as a consequence of the no-action alternative).

2.2.1 No-Action Alternative

Under the no-action alternative, DOE would not provide cost-shared funding to the Babcock Borsig team for demonstrating LEBS technology. The commercial readiness of the LEBS technology for higher efficiency, cost-competitive power generation with improved removal of SO_2, NO_x, and particulate matter would not be demonstrated at Elkhart, Illinois, because the Babcock Borsig team would not assume the financial risk associated with the project without DOE funding. The technology probably would not be demonstrated elsewhere in the near future because no plans for a similar project are known to exist. Consequently, commercialization of the technology would be delayed or might not occur because the utility and industrial sectors tend to apply known and previously demonstrated technologies rather than new and unproven technologies.

Under the no-action alternative, the only reasonably foreseeable scenario is that the proposed power plant in Elkhart, Illinois, would not be built. This scenario would not contribute to DOE's LEBS goal of demonstrating promising coal technologies that operate efficiently and decrease the cost of electricity while reducing emissions of SO_2, NO_x, and particulate matter below mandated levels. In the absence of technology demonstration, opportunities for penetration of the technology into the commercial marketplace would not be realized. Further, the mutually beneficial arrangement between the proposed power plant and the adjacent existing coal mine would not be realized (i.e., no coal would be provided by the coal mine to the power plant, and no source of low-cost electricity would be available to the mine from the local power grid). Temporary construction jobs and permanent new jobs at the power plant and the coal mine would not be created. Potential benefits to regional air quality that could result from the electricity generated by the proposed plant displacing electricity supplied by older, less efficient power generation facilities that have higher air pollution emission rates would not be realized.

Under the no-action scenario, no construction activities or changes in operations at the proposed site would occur. No change in current environmental conditions at the site would result, and the impacts would remain unchanged from the baseline conditions. Table 2.2.1 presents a comparison of potential impacts from the proposed action and the no-action alternative.

2.2.2 Alternatives Dismissed from Further Consideration

The following sections discuss alternatives that were initially identified and considered by DOE and the Babcock Borsig team, and alternatives that were raised during the scoping process. The Babcock Borsig team conceived, designed, and proposed the 91 MW power plant in Elkhart, Illinois, in response to the LEBS solicitation that was issued by DOE in December 1990 (Section 1.1). Because DOE's role would be limited to providing cost-shared funding for the proposed power plant, reasonable alternatives are narrowed. The following candidate alternatives were identified and considered but were dismissed from further consideration.

2.2.2.1 Alternative Sites

Several sites were considered by the Babcock Borsig team for the proposed power plant. A site at an industrial park in Du Quoin, Illinois, was evaluated. Although the site was near several existing coal mines, coal would need to be delivered to the site by truck, which would substantially increase the cost of coal delivered to the site in comparison with the cost of coal delivered to the Elkhart site from the Turris Mine. Also, the Du Quoin site did not offer the required infrastructure and support facilities for power plant operations, such as water supply and storage, wastewater treatment, and roads designed for coal truck traffic. Finally, the Du Quoin site was on the edge of town near several residences.

The retired Chanute Air Force Base in Rantoul, Illinois, was also considered. Although this site contained infrastructure to support the proposed power plant, including several coal-fired boilers used for district heating, the cost of transporting coal to the site would be high due to the distance from any active mines.

The Babcock Borsig team selected the Turris Mine site due to the ready availability of a coal source and the favorable infrastructure. Coal would be available at an attractive price without extra hauling and handling. Personnel and administrative facilities could be shared by operations at the coal mine and the proposed power plant. Also, existing land use at the Turris Mine, consisting of industrialized activities remote from residences, would be compatible with the proposed plant.

2.2.2.2 Alternative Technologies

As discussed in Section 1.1, the project proposed by Babcock Borsig Power was selected to demonstrate a particular type of low emission combustion technology. DOE's National Energy Technology Laboratory conducted a competitive solicitation in 1990 to identify industry-conceived LEBS technologies for cost-shared support. DOE selected the LEBS technology proposed by the Babcock Borsig team for Phase IV demonstration. Coal-fired projects using other technologies might not achieve the LEBS goals (Section 1.2.1), and other technologies and approaches that do not use coal (e.g., natural gas, wind power, solar energy, and conservation) would not achieve those goals. Furthermore, because of fuel availability, a coal-fired facility would be the only reasonable power generation technology for location at the Elkhart, Illinois, site.

2.2.2.3 Other Alternatives

Other alternatives, such as delaying or reducing the size of the proposed power plant, have been dismissed as not reasonable. Delaying the construction or operation of the plant would not result in any reduction of environmental impacts, but delays could adversely affect DOE's plans for demonstrating the technology. The design size proposed by Babcock Borsig for the power plant was selected to assure technology operations at a scale sufficient to convince utility companies that the technology, once demonstrated at this scale, could be applied to similarly sized or larger combustors, without further scale-up to verify operational or economic performance.

Table 2.2.1. Potential impacts of the proposed action and the no-action alternative

Proposed action	No-action alternative
Aesthetics	
Construction would produce minor short-term visual impacts, but visual characteristics would not differ appreciably over the long term from those currently existing at the site. Except for the boiler stack, structures for the LEBS proof-of-concept plant would be comparable in stature and architecture with existing structures at the Turris Mine's coal handling and processing complex immediately south of Township Road 600N from the site of the proposed plant and with the cleaned coal storage and loading facilities that would be adjacent to the proposed plant north of the road. The boiler stack, with a height of 293 ft, would represent a 36 ft (14%) increase in vertical profile compared to the highest structures currently existing at the Turris Mine.	The viewing landscape, which currently includes industrial buildings, coal storage silos (257 ft), coal piles, coal conveyors, and waste disposal ponds, would remain unchanged. No scenic vistas or aesthetic landscapes are present in the project area.
Atmospheric resources	
Construction No exceedances of the Federal and state-adopted National Ambient Air Quality Standards (NAAQS), including the standard for 24 hour averaged PM_{10}, would be expected beyond about 300 ft from the edge of the construction area. For annual averaged PM_{10}, total concentrations would be less than 70% of the relevant NAAQS at 300 ft from the edge of the construction area.	*Construction* Atmospheric resources would be unaffected because no construction associated with the proposed power plant would occur. No change in ambient air quality, which attains Federal and state standards for quality, would occur.
Operation The Prevention of Significant Deterioration (PSD) modeling analysis shows that expected pollutant concentrations would typically be <10% and would always be <20% of allowable increments. PSD increments would also not be exceeded when other PSD emission sources in the region are included in the modeling. No exceedances of the NAAQS would be expected from the combined emissions of the proposed plant and other regional sources. The contribution of emissions from the proposed plant to acidic deposition and to global climate change would be expected to be negligible. Relatively small amounts of non-criteria pollutants, including arsenic, beryllium, sulfuric acid mist, mercury, hydrogen chloride, organic emissions, and various heavy metals, would be produced. The levels of non-criteria emissions	*Operation* Existing air quality in the area, which is in attainment of the NAAQS, would remain essentially unchanged. Potential benefits to regional air quality that could result from the electricity generated by the proposed plant displacing electricity supplied by older, less efficient facilities that have higher air pollution emission rates would not be realized.

Table 2.2.1. Potential impacts of the proposed action and the no-action alternative

Proposed action	No-action alternative
would pose a negligible risk to workers and members of the public.	
Water quality and use	
Construction	*Construction*
The construction contractor would either provide potable water from off-site sources or obtain water from the new wells installed during construction. The field drainage water system and groundwater obtained from the wells would be used to provide water for construction activities. The anticipated small additional demand would not be expected to cause the water sources to be overdrawn. Impacts attributable to runoff, erosion, sedimentation, and accidental spills would be minimal.	Because no construction would occur, existing water uses and quality would be unaffected.
Operation	*Operation*
Operation of the proposed plant would require about 1,195 gpm of water, of which 1,145 gpm would be provided from a retention pond installed to capture water from field drainage runoff. No new water discharge would result. Neither a small volume (3 gpm) of sanitary water inflow to the Turris Mine's existing sewage treatment plant nor inflow of 62 gpm from the proposed power plant into the Turris Mine's water pond would be expected to result in any substantive change or impacts to operations at the Turris Mine.	Existing impacts on water quality and use from operations at the Turris Mine would continue. Water supply, use, sampling, and discharge activities at the mine comply with applicable regulations and would be expected to remain essentially unchanged. The mine currently discharges water off-site only during substantial rainfall events that cannot be controlled with the mine's pumping system.
Geology and groundwater resources	
Groundwater consumption by the village of Elkhart (35 gpm) and for existing operations at the Turris Mine (62.5 gpm) would not be expected to change. Major buildings and structures would not be constructed in areas where subsidence from mining activities would be likely, and the low level of seismic activity in the area would not be sufficient to cause appreciable damage. Damage to the plant from surface subsidence (from coal mine collapse) or earthquakes would not be expected. Soil compaction and paving on about 3 acres of the 5 acre plant site would reduce soil permeability and increase storm water runoff rates. Power plant operations would not produce any discharges that would contaminate groundwater supplies.	Existing consumptive uses of groundwater in the area would continue. The village of Elkhart would continue to withdraw approximately 35 gpm, and 62.5 gpm would continue to be withdrawn by the Turris Mine to support on-going operations. Groundwater quality monitoring at the Turris Mine would continue.
Water requirements for operation of the proposed power plant would be obtained from	

Table 2.2.1. Potential impacts of the proposed action and the no-action alternative

Proposed action	No-action alternative
field drainage runoff and new groundwater wells. The Pearl/Kansan outwash aquifer would be capable of supporting the plant's water requirement, if needed during periods of drought, but declines in groundwater levels may occur in nearby water supply wells. Also, water quality in the aquifer could potentially be degraded as a result of excessive *drawdown*. A portion of the water from the proposed power plant's cooling tower would be discharged to the Turris Mine's fresh water pond for use in mine operations, which could reduce the amount of groundwater usage by the mine. Groundwater monitoring would be conducted to periodically test drawdown and quality of the aquifer feeding water supply wells, including the village of Elkhart's wells. If results from the groundwater testing program indicate water quality or flow problems for the Elkhart water supply, power plant output would be reduced, or the plant could temporarily suspend operations. New sources of water supply for the plant and for the community would be examined.	
Solid waste	
No adverse environmental impacts would be expected during construction and operation of the plant. Construction wastes would be transported to off-site landfills. Vitrified ash (9,400 lb/hr, or 41,172 tons per year) would be marketed for sale. If markets can not be established, the materials would undergo disposal at the mine. Commercial-grade gypsum (about 24,000 lb/hr, or 105,120 tons per year) would be moved for permitted disposal at the mine or at a permitted CBEC site. Waste disposal capacity at the mine and at off-site locations would be adequate to handle all construction and operation wastes.	The Turris Mine currently accepts about 135,000 tons per year of coal combustion wastes from off-site users. That rate would be expected to continue. The additional wastes resulting from construction and operation of the proposed power plant would not be generated.
Ecological resources	
For both construction and operation of the proposed power plant, no adverse impacts on terrestrial or aquatic ecosystems would be expected on the plant site or in the immediate vicinity. No threatened or endangered species are found on or near the site. Expected impacts on biodiversity would be minimal.	Existing terrestrial and aquatic resources, which are not regarded as particularly important or unique, would remain essentially unchanged. The number of plant and animal species present on the mine property is quite low relative to natural grasslands and forests typical of the region.

Table 2.2.1. Potential impacts of the proposed action and the no-action alternative

Proposed action	No-action alternative
Cultural resources	
No known historic or archaeological resources exist on the plant site. However, if such resources would be discovered during construction, work would be stopped and an archaeologist with the Illinois Historic Preservation Agency would be contacted.	Operations at the Turris mine are not affecting cultural resources. A Phase I cultural resources survey indicated that the site does not contain any archaeological resources.
Floodplains and wetlands	
Flooding at the plant site would not be expected, and floodplain encroachment would not occur. Neither construction nor operation of the proposed plant would require or create any stream diversions that would alter existing off-site drainage patterns. No wetland areas would be affected.	Floodplains in the area would not be affected by the no-action alternative, and the ponds on the Turris Mine's property have little or no significance as wetlands. Examination of Natural Wetland Inventory maps, visual inspections, and consultations with the U.S. Army Corps of Engineers and the Illinois Department of Natural Resources confirm the absence of jurisdictional wetland resources in areas potentially affected by the proposed power plant.
Socioeconomics	
Construction and operation of the proposed power plant would result in a small increase in construction (180), operating (25), and mining (20) jobs. These beneficial increases in employment would not be expected to create any strains on housing and public services.	The anticipated minor or temporary increases in population, employment, and per-capita income and the resulting minor additional demands on housing and public services from power plant construction and operation would not occur.
Human health	
No adverse impacts to public health would be anticipated as a result of construction and operation of the proposed plant. As identified in the discussion of atmospheric resources, emissions of air pollutants would not result in exposure levels that would produce adverse effects on public health or welfare.	No changes from existing conditions would be expected.
Worker safety	
Construction	*Construction*
Based on accident rates for the U.S. construction industry, about 5 injuries would statistically be expected to occur among the average of 100 workers.	Because no construction would occur at the site, no potential for construction-related injuries would exist.
Operation	*Operation*
Worker safety and health considerations would be dominated by physical hazards, primarily equipment accidents, noise, heat stress,	Physical hazards associated with operation of the proposed plant would not exist.

Table 2.2.1. Potential impacts of the proposed action and the no-action alternative

Proposed action	No-action alternative
and confined spaces. Regulations established by the Occupational Safety and Health Administration (OSHA) and corporate policies of the BBP team would be expected to mitigate the risks from these types of safety hazards.	
Noise	
Construction Expected noise levels from construction would be <54 dB(A) at 3,000 ft from the site, which is within EPA guidelines for preventing activity interference and annoyance.	*Construction* Current ambient noise levels, which are characteristic of the relatively quiet rural environment, would not change.
Operation No significant noise impacts would be expected.	*Operation* Current ambient noise levels, which are characteristic of the relatively quiet rural environment, would not change.
Traffic	
For both construction and operation, on-site and off-site transportation corridors have sufficient capacity to handle expected increases in traffic without significant adverse impacts. A maximum daily traffic increase of 180 passenger vehicles and 75 truck vehicles during construction and a permanent increase of 45 passenger vehicles and 35 truck vehicles during operation of the power plant would result. No increase in coal truck traffic would occur.	Existing traffic patterns would remain relatively unchanged. A maximum traffic volume of 800 truck-trips per day exists on Township Road 600N; this traffic is spread over a 24 hour period, with about two-thirds occurring during the day.
Land use	
No adverse impacts to on-site or off-site land use would be expected to result from construction and operation of the proposed plant. A 22-acre parcel of land currently leased by Turris Coal Company for corn and soybean production would be used for construction of a water retention pond. About 0.01% of the land that is currently used for crop production in Logan County would be used for the new water retention pond.	The current land uses in the area – primarily the Turris Mine and agriculture – would continue.
Environmental justice	
No disproportionate adverse impacts to minority or low-income populations would be expected because the percentages of minorities and households below the poverty level in Elkhart are less than those in Logan County and Illinois, and because no adverse impacts to any nearby residents would be anticipated.	No environmental justice impacts would occur.

2.2.3 Preferred Alternative

The NEPA regulations established by the Council on Environmental Quality (40 CFR 1502.14e) require a Federal agency to identify in a Final EIS, or in a Draft EIS if known at the time of Draft EIS preparation, the preferred alternative or alternatives for accomplishing the agency's purpose. A preferred alternative is the alternative that an agency believes would best fulfill the agency's statutory mission and responsibilities after thorough consideration of economic, environmental, technical, and other factors. For DOE's purpose of demonstrating the commercial viability of integrated, reliable, low cost, and highly efficient technologies for achieving reduced emissions from pulverized coal-fired power generation systems, DOE's preferred alternative is the proposed action for providing cost-shared funding to BBP for design, construction, and operational demonstration of the proposed LEBS power plant at Elkhart, Illinois.

3.0 EXISTING ENVIRONMENT

This section profiles the environmental resources in the vicinity of the proposed power plant site at Elkhart, Illinois. The resources discussed include relevant physical, biological, social, and economic conditions that could be affected by implementation of the proposed action or the no-action alternative. Each resource is described sufficiently to provide the necessary background and context for assessing the potential impacts, which are presented in Section 4.0.

3.1 SITE DESCRIPTION AND AESTHETICS

The proposed plant would be located on a graded, nearly level, grassy field accessed by a paved road. The surrounding terrain is primarily flat to rolling. The principal topographic feature in the vicinity is Elkhart Hill, the highest point in Logan County. This feature is located slightly over 1 mile northwest of the site and has a maximum elevation of about 200 ft above site grade (Figure 2.1.2). Because the proposed plant site is adjacent to Turris Coal Company's underground coal mine and surface coal processing operations (Figure 2.1.4), the viewing landscape includes industrial buildings, coal storage silos with 257 ft height, coal piles, coal conveyors, and waste disposal ponds surrounded by earthen berms. Electric transmission lines and towers traverse the mine property. Although several instances of mine subsidence have been detected at the surface of the mine property, no mining has occurred beneath the plant site. Other land use in the rural area surrounding the site is mainly agricultural. No scenic vistas or aesthetic landscapes are present in the area.

3.2 ATMOSPHERIC CONDITIONS

3.2.1 Climate

Illinois has a continental climate characterized by warm, humid summers and moderately cold winters (Gale Research Company 1985; 1996). Summer temperatures reach 90°F or above on an average of 30 days per year, as measured at Capital Airport in Springfield, about 17 miles southwest of the proposed plant site. The all-time maximum temperature of 112°F was recorded in July 1954. Winter temperatures drop to 0°F or below on an average of 10 days per year. The all-time minimum temperature of -22°F was recorded in February 1963.

The majority of the region's precipitation is supplied by air moving northward from the Gulf of Mexico. As recorded at Capital Airport, annual precipitation averages about 35 in., and precipitation is most abundant from March through September. Precipitation during the autumn, winter, and early spring tends to fall uniformly over large areas, while late spring and summer rainfall occurs primarily as brief showers affecting relatively small areas. As is typical of continental climates, precipitation can be highly variable. The driest year of record was 1953, with only 24.0 in. of precipitation, while the wettest year was 1990, with 52.7 in. of precipitation. The driest summer (June to August of 1988) yielded only 3.9 in. of rainfall, while the wettest summer (1981) had 24.9 in. of rainfall. During intervals as short as one month, extreme minima can approach zero – for example, only a trace of precipitation was recorded at Capital Airport in September 1979. The maximum monthly precipitation of 10.8 in. was recorded in July 1981.

On average, forty (40) of the 50 days per year with thunderstorms occur during the spring and summer. Hail occurs on an average of less than once per year. The maximum 24 hour precipitation of 6.12 in. occurred in December 1982. On average, snowfall amounts of 1 in. or more occur 8 days per year. The maximum 24 hour snowfall of 11 in. was recorded in December 1973. Moderate to heavy ice storms occur about once every 4 or 5 years. Heavy fog occurs about 17 days per year.

The *wind rose* in Figure 3.2.1 shows that the prevailing wind at Capital Airport is from the south and the mean wind speed is about 11 mph. The period of record (1987-1991) for the wind rose was selected to coincide with the period of record used in the air dispersion modeling (Section 4.2.2.1), as determined to be representative of local meteorological conditions based on reviews by the IEPA. The wind speed and the mixing height (the height above ground to which appreciable vertical atmospheric mixing occurs) are important factors influencing atmospheric dispersion of pollutants. If mixing height and wind speed are both very low, atmospheric dispersion of pollutants is limited and the meteorological potential for air pollution is high. Such conditions are infrequent in central Illinois – according to Holzworth (1972), less than two days per year have a high meteorological potential for air pollution.

3.2.2 Air Quality

National Ambient Air Quality Standards (NAAQS) (Table 3.2.1) exist for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), ozone (O_3), carbon monoxide (CO), lead (Pb), and particulate matter less than or equal to 10 μm in aerodynamic diameter (PM_{10}) and less than or equal to 2.5 μm in aerodynamic diameter ($PM_{2.5}$). The pollutants covered by the NAAQS are called criteria pollutants because the criteria for their regulation must be published, reviewed, and updated periodically to reflect the latest scientific knowledge (Clean Air Act, Section 108). On July 18, 1997, EPA promulgated an 8 hour O_3 NAAQS to replace the 1 hour standard (62 *FR* 38856) and added the NAAQS for $PM_{2.5}$ (62 *FR* 38652). These standards have survived court challenges (U.S. Supreme Court 2001), but plans for their implementation, which would require collection of ambient air monitoring data for 3 years to determine compliance, were delayed.

The NAAQS (40 CFR Part 50(e)) are expressed as concentrations of pollutants in the ambient air (i.e., in the outdoor air to which the general public has access). Primary NAAQS define levels of air quality that the U.S. Environmental Protection Agency (EPA) deems necessary, with an adequate margin of safety, to protect human health. Secondary NAAQS are similarly designated to protect human welfare by safeguarding environmental resources (such as soils, water, plants, and animals) and manufactured materials. Primary and secondary standards are currently the same for all pollutants and averaging periods, except for 3 hour SO_2 averages, which have a secondary standard only, and CO, which has only a primary standard. States may modify the NAAQS to establish more stringent standards, or states may set standards for additional pollutants. Illinois has adopted the NAAQS as the state standards (Illinois Administrative Code, Title 35, Part 243).

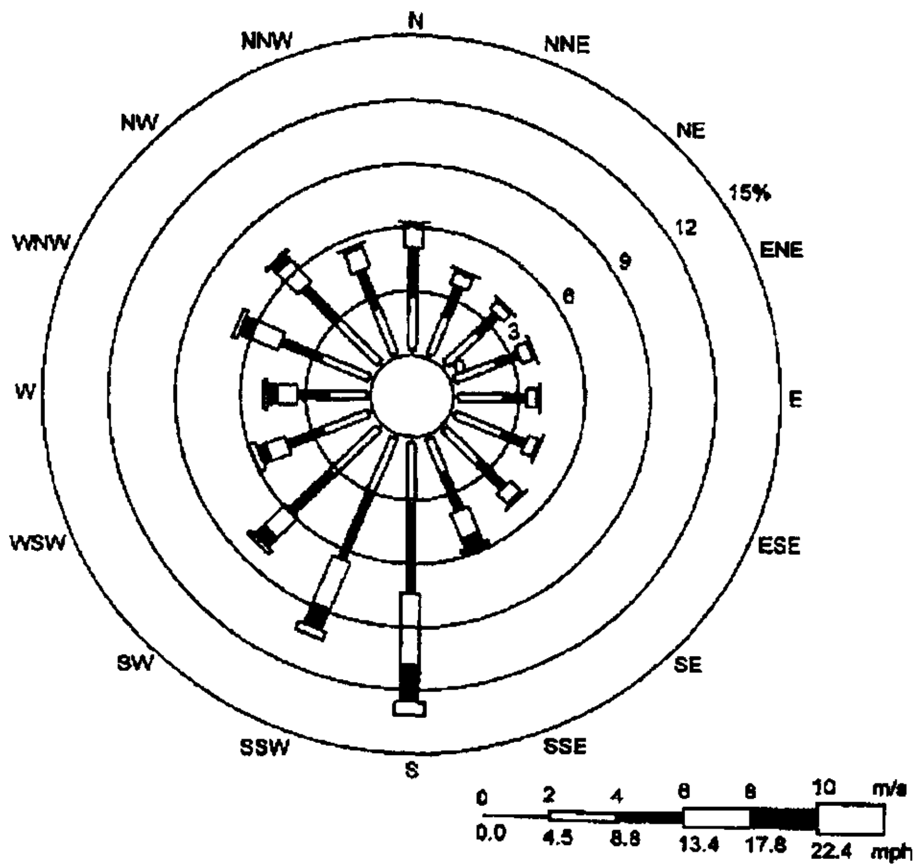

Figure 3.2.1. Wind rose for the Capital Airport in Springfield, Illinois (1987-91). The frequency of blowing wind is plotted as bars that extend to the center of the diagram in the direction that the wind is blowing. Wind speeds are denoted by bar widths and shading; the frequency of wind speed within each wind direction is depicted according to the length of that section of the bar. Note that because the wind rose displays directions **from** which the wing blows, emissions would travel downwind in the opposite direction.

Air quality in the Elkhart area is good, as evidenced by the fact that the Elkhart region is in attainment with the NAAQS. Measured ambient concentrations of the criteria air pollutants are compared with the NAAQS in Table 3.2.1 for locations nearest to Elkhart (with the exception that Decatur is used instead of Springfield for SO_2 because the ambient air monitor at Springfield measures the downwind air quality resulting from emissions of a nearby power plant, which would not be representative of the Elkhart area). The table indicates that the concentrations of all criteria pollutants, with the exception of ozone, are less than 55% of their respective standards, and the concentration of ozone is less than 85% of its standard.

Table 3.2.1. Existing air quality for the Elkhart area, as measured at Springfield, Decatur, and East St. Louis during 1997–2001

Pollutant[a]	Location of monitor	Year	Averaging period	Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)[b]	Percentage of standard
SO_2	Decatur	1999	3-hour	165[c]	1300	13
		1999	24-hour	71[c]	365	19
		2000	Annual	13[d]	80	16
NO_2	East St. Louis	2001	Annual	36[d]	100	36
CO	Springfield	1998	1-hour	7,360[c]	40,000	18
		1999	8-hour	2,760[c]	10,000	28
Pb	Decatur	1997	Calendar quarter	0.03[d]	1.5	2
PM_{10}	Springfield	2000	24-hour	81[e]	150	54
		2000	Annual	26[d]	50	52
$PM_{2.5}$		*f*	24-hour	*f*	65[f]	*f*
		f	Annual	*f*	15[f]	*f*
O_3	Springfield	2001	1-hour	196[g]	235[g]	83
		f	8-hour	*f*	157[f]	*f*

[a] Chemical symbols for the pollutants are as follows: SO_2, sulfur dioxide; NO_2, nitrogen dioxide; CO, carbon monoxide; Pb lead; O_3, ozone. PM_{10} and $PM_{2.5}$ refer, respectively, to particulate matter less than 10 or 2.5 μm in diameter.

[b] National Ambient Air Quality Standards (NAAQS) in micrograms per cubic meter ($\mu g/m^3$).

[c] In accordance with the standard, the highest value for each year has been excluded and the highest of the remaining concentrations is used.

[d] In accordance with the standard, the maximum annual (or quarterly, for lead) concentration is used.

[e] The highest 24-hour average of PM_{10} in the 5-year period is used to ensure that the value given does not underestimate the 99th percentile (averaged over 3 years of data) that is to be compared with the standard.

[f] *Standards for $PM_{2.5}$ and an 8-hour standard for O_3 have recently been established* (*FR 62:138 Friday, July 18, 1997*). These standards apply to 3-year averages; data for comparison with these standards are not yet available.

[g] This standard is 0.12 parts per million (ppm), or 235 $\mu g/m^3$ [40 CFR 50(9)]; three days with exceedances are allowed over a 3-year period. EPA conventionally has interpreted an exceedance as a concentration of 0.13 ppm or greater, after rounding to two places (*FR* 60:44 Tuesday, March 7, 1995, page 12464; *FR* 62:139 Monday, July 21, 1997, page 38928). A concentration of 0.11 ppm (216 $\mu g/m^3$) was measured on one day during 1999 and one day during 2001; concentrations of 0.10 ppm (196 $\mu g/m^3$) were measured on several days during 1998-2001.

In addition to the NAAQS, which provide an upper bound on allowable pollutant concentrations, national standards have been established to preserve air quality in areas that are more pristine than required by the NAAQS (40 CFR 51.166). These Prevention of Significant Deterioration (PSD) standards differ from the NAAQS in that the NAAQS specify maximum allowable concentrations of pollutants, while PSD requirements provide maximum allowable increases in concentrations of pollutants for areas already in compliance with the NAAQS. PSD standards are therefore expressed as allowable increments in the atmospheric concentrations of specific pollutants. PSD increments are particularly relevant when a major proposed action involving a new source or a major modification to an existing source may degrade air quality without exceeding the NAAQS. PSD increments have been established for SO_2, NO_2, and PM_{10}. One set of allowable increments exists for Class II areas, which cover most of the United States, and a much more stringent set of increments exists for Class I areas, which include many national parks and monuments, wilderness areas, and other areas, as specified in 40 CFR 51.166(e). Mingo Wilderness Area, which is located about 210 miles south-southwest of Elkhart, is the nearest PSD Class I area.

Other pollutants (e.g., benzene, beryllium, and mercury) are present in the ambient air of the Elkhart area in varying amounts, which depend on the magnitudes and characteristics of their emission sources, the distance from each source, and the residence time of each pollutant in the atmosphere. Many of these pollutants are difficult to measure because they are present only in extremely small concentrations. Measurements of existing ambient air concentrations for many hazardous pollutants are, at best, very sporadic. These pollutants are regulated at the source of emissions by the National Emissions Standards for Hazardous Air Pollutants (40 CFR 61; 40 CFR 63).

3.3 SURFACE WATER RESOURCES

3.3.1 Hydrology

The proposed site is located within the Sangamon River watershed (DMC 1991; TCC 1996; USGS 1969, 1980a, 1980b, and 1982). The Sangamon River and its tributaries drain the central part of the state of Illinois above Springfield and below Congerville (northwest of Bloomington) into the Illinois River (Figure 3.3.1), which in turn flows into the Mississippi River. Lake Fork Creek flows near the proposed site and empties into Salt Creek, which then discharges into the Sangamon River.

The proposed site is located approximately 1.5 miles west of Lake Fork Creek (Figure 3.3.2). Runoff from the site is conveyed to Lake Fork Creek by an unnamed northeasterly flowing tributary. A channelized drainage ditch is located adjacent to the proposed site and conveys runoff from the site into the Lake Fork Creek watershed. The figure depicts the approximate location of an existing collection pipe on the southeast corner of the Turris Mine property. This pipe provides the discharge from the existing field tile drain system.

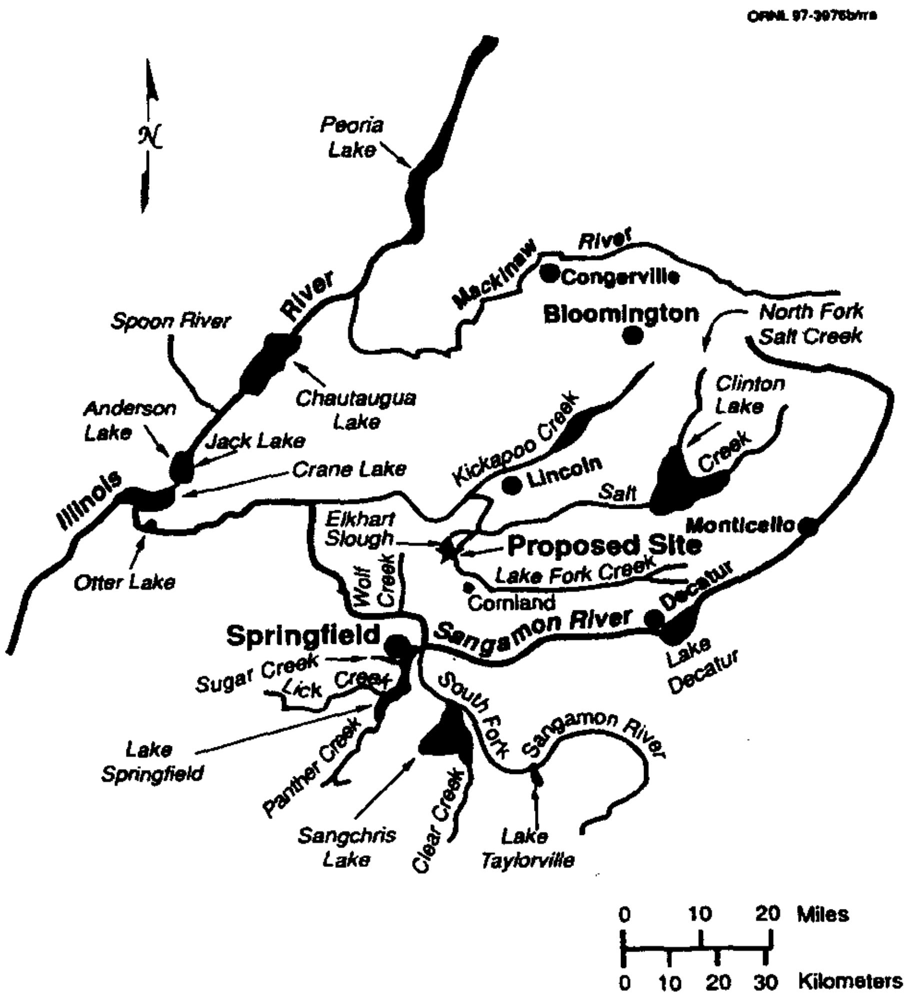

Figure 3.3.1 Surface water features in the central Illinois region around the site proposed for the power plant

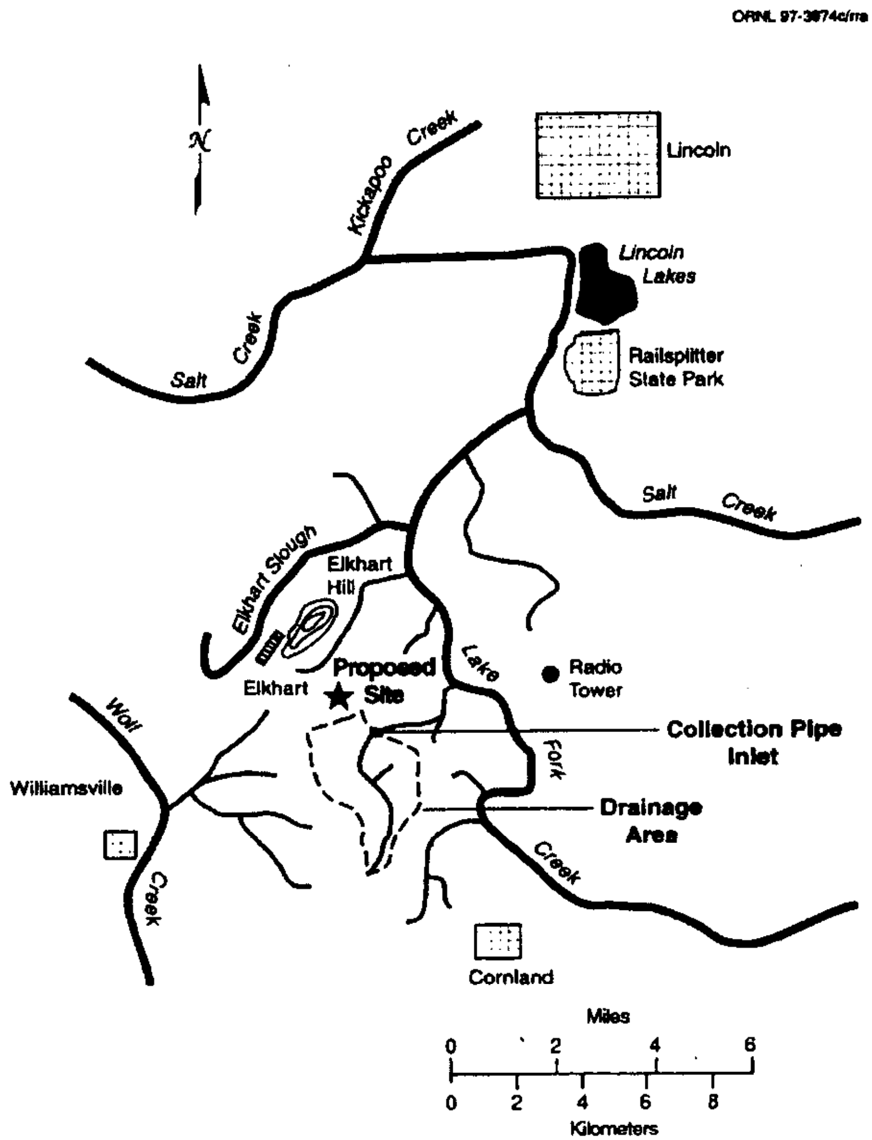

Figure 3.3.2 Surface water drainage features in the vicinity of the proposed power plant site

The headwaters of Lake Fork Creek lie east of Cornland (Figure 3.3.1) and consist of Hunter Slough and the North and South Forks of Lake Fork Creek (USGS 1969 and 1980b). No lakes or reservoirs regulate the flow of Lake Fork Creek, which discharges into Salt Creek downstream from the proposed power plant site at a confluence just south of Railsplitter State Park (Figure 3.3.2). Partial regulation of water flow in Salt Creek is provided by Clinton Lake, which is located east of Lincoln and east-northeast of the proposed power plant site (Figure 3.3.1).

The annual mean flow in Lake Fork Creek, as measured at the U.S. Geological Survey's gauging station for the Creek at Cornland, IL, approximately 5 to 6 stream miles upstream from the site, measured 168 ft^3/s (about 75,400 gpm) for the period of record from water year 1948 to 1995 (Wicker, LaTour, and Maurer 1996). Five tributaries feed Lake Fork Creek between the gauging station and the proposed plant site; thus, water flow near the proposed plant site would be greater than the recorded water flows near Cornland. The highest annual mean flow was about 167,000 gpm, and the lowest annual mean flow was about 4,000 gpm. The instantaneous peak flow of 4 million gpm was recorded on April 12, 1979, and the instantaneous low flow of 135 gpm occurred on September 16, 1988. The flow exceeded 7 ft^3/s (about 3,140 gpm) at least 90% of the time. A peak flow of 13 million gpm was estimated for the flood of May 1943, which is the extreme outside of the 1948 to 1995 period of record (Wicker, LaTour, and Maurer 1996).

3.3.2 Water Quality and Use

Water supply in Logan County is obtained primarily from groundwater (LaTour and Ackermann 1990). The volume of groundwater withdrawn for use is approximately ten times greater than the volume of surface water consumption. Surface water use seldom exceeds 694 gpm (1 MM gpd), while groundwater withdrawals range from 694 gpm to 6,944 gpm (1 to 10 MM gpd).

Water for the Turris Mine is obtained from three wells that pump groundwater – one potable water well and two nonpotable *process water* wells (Section 3.4.3). The groundwater supply for process water is supplemented with storm water runoff collected from mine property. The storm water runoff is contained by collection ponds and then routed into the process water distribution system. The potable water well provides groundwater using a separate distribution system for drinking and sanitation.

Wastewaters from the Turris Mine are discharged into the wastewater treatment system for the coal mining/preparation complex and then recirculated by the process water distribution system for continual use (Beittel and Darguzas 1996). Sanitary wastes associated with mining are treated in the existing dual-cell aerated lagoon at the Turris Mine.

Turris Coal Company attempts to retain all water on the mine property for use in coal processing, and water discharges from the site occur only during substantial rainfall events that cannot be controlled with the mine's pumping system. Monitoring records support a conclusion that discharges from water collection ponds on mine property are rare events that occur only a few days per year for most ponds. Any discharge from the ponds is regulated under a National Pollutant Discharge Elimination System (NPDES) permit. Discharges from the ponds are received by an unnamed tributary of Lake Fork Creek. Figure 3.3.3 depicts the layout of the freshwater pond, sediment ponds, and the slurry pond disposal area (the slurry impoundment), which are all south of Township Road 600N, on Turris Coal Company property.

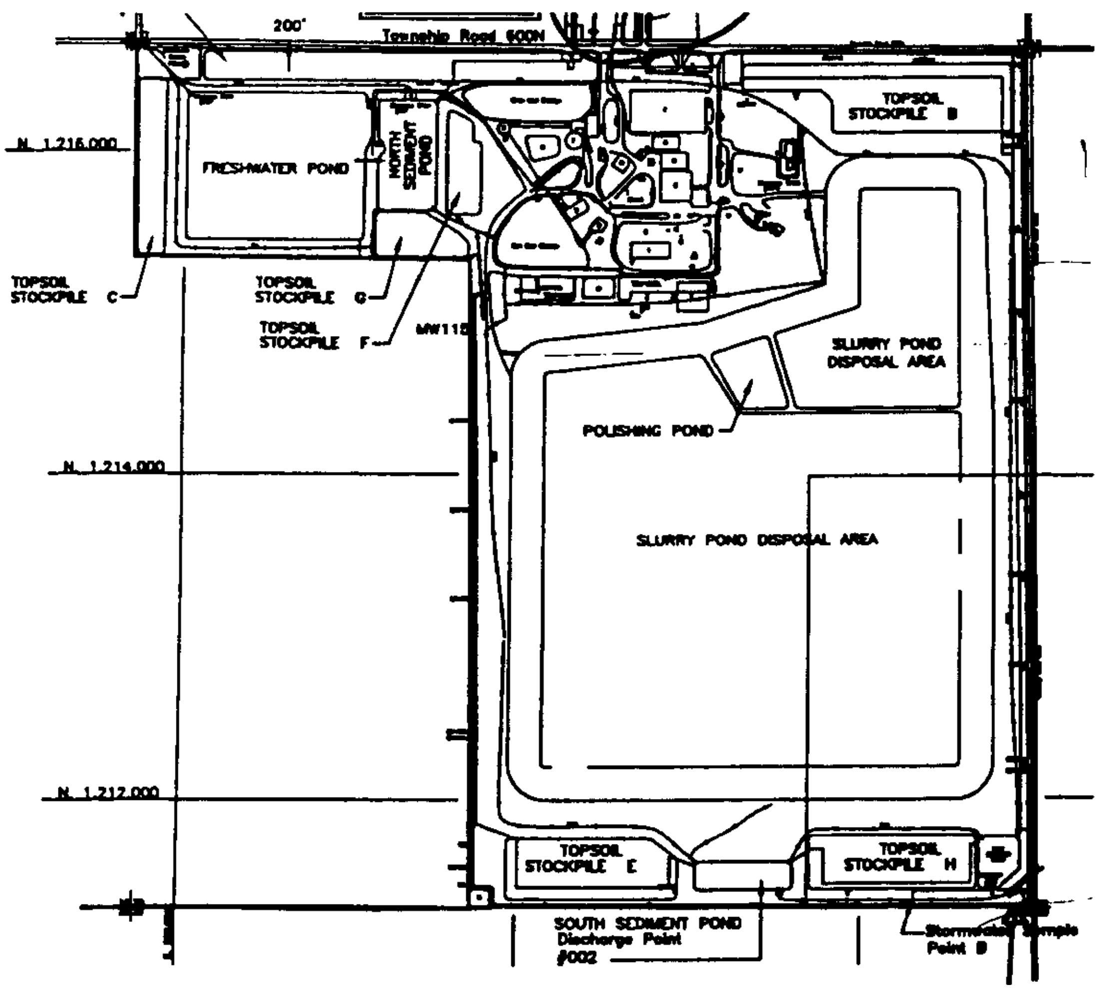

Figure 3.3.3. Layout of existing ponds on Turris Coal Company property

The NPDES permit (No. IL0061956) issued by the Illinois Environmental Protection Agency (IEPA) describes the discharge limitations under which the Turris Coal Company is allowed to discharge to off-site surface waters from operations at the Turris Mine (IEPA 1995). The current permit was issued on October 6, 2000, and covers ten different outfalls to surface waters. Storm water runoff from the preparation plant and refuse disposal areas is directed to the north, south, and east sedimentation ponds with outfalls numbered 001, 002, and 003, respectively. Outfall 001A discharges from the settling pond used by the sewage treatment facility into the north sedimentation pond (with outfall 001). Outfall 006 is for storm water runoff from the freshwater pond. Outfalls 004 and 005 were permitted for a train loadout facility that was not built, about 2 miles west of the Turris Mine, and are classified as alkaline mine drainages. Outfalls 007 and 008 were permitted for a coal combustion waste disposal facility north and east of the truck loadout area; that waste disposal facility has not been built. Outfall 009 is located at the sediment pond at the Williamsville Portal Facility.

Outfalls 001, 002, 003, and 006 are classified as alkaline mine drainages, and outfall 001A is classified as a sanitary discharge. Outfalls 001 (which receives the discharge from 001A), 002, 003, and 006 discharge into unnamed tributaries of Lake Fork Creek, while outfalls 004 and 005 discharge into unnamed tributaries of Wolf Creek.

Monitoring requirements in the NPDES permit state that the outfalls should be sampled three times monthly and analyzed for total suspended solids, settleable solids, iron, pH, alkalinity/acidity, sulfates, chlorides, and manganese. The permit specifies monthly average and daily maximum concentration limits that are not to be exceeded. If limits are exceeded, Turris Coal Company is required to file a report of noncompliance. Based on quarterly NPDES monitoring reports, four instances of noncompliance occurred from January 1993 to May 1997. The maximum daily pH criterion of 9.0 was exceeded in April 1994 at outfalls 001 and 003, and the maximum daily chloride criterion of 1,000 mg/L was exceeded in October 1996 and March 1997 at outfall 006.

3.4 GEOLOGY AND GROUNDWATER

3.4.1 Local Geology

The Turris Mine is located at an elevation of about 585 ft above mean sea level and is situated above the main channel of the Middletown bedrock valley, which is a tributary to the buried Mahomet Valley (Rapps 1989). This bedrock valley is filled with approximately 180 to 200 ft of *unconsolidated sediment* (Quaternary deposits) laid down by glaciers that advanced and retreated during the Pleistocene Epoch. The following Quaternary deposits (Figure 3.4.1) have been identified, in descending order from the ground surface (Rapps 1989; 1993):

- Peoria *Loess* (or weathered *glacial drift*) – loessial (windblown) deposits of Wisconsinan Age, consisting primarily of silt with some clay and sand, with a thickness of about 15 to 20 ft;

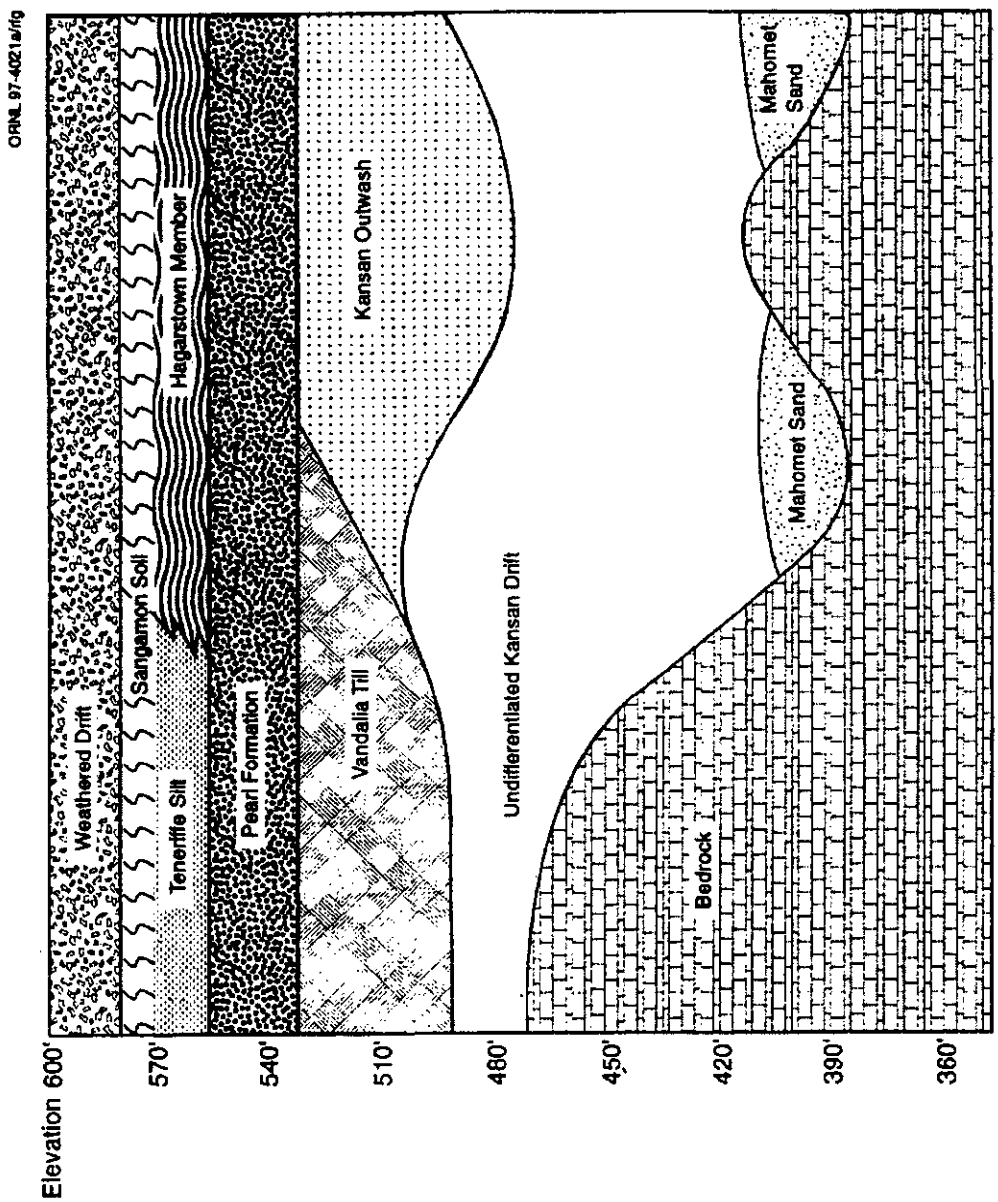

Figure 3.4.1 Generalized hydrogeologic cross-section of the Turris mine site.

Figure 3.4.1. Generalized hydrogeologic cross-section of the Turris Mine site

- Sangamon Soil – consisting of the organic-rich Robein silt, the weathered Roxana Silt, and the Berry Clay *Member*, developed during the Sangamon inter-glacial period between the Wisconsinan and Illinoian glaciations and ranging in thickness from 0 to 8 ft;
- Teneriffe Silt/Hagarstown Member – glacial-*fluvial* or glacial-*lacustrine* deposits of Illinoian Age, consisting primarily of sandy silt with interbeds of sand, clay, and gravel, with an average thickness of about 35 ft;
- Pearl *Formation* – glacial *outwash* deposits of Illinoian Age, comprising hard, well-sorted, fine- to medium-grained sand with some gravel, ranging in thickness from 4 to 20 ft;
- Vandalia *Till* – gray, hard, silty clay with some sand and pebbles of Illinoian Age, ranging in thickness from 0 to 50 ft;
- Kansan outwash – sand and gravel glacial outwash deposits of Kansan Age, ranging in thickness from 0 to 75 ft;
- Undifferentiated Kansan drift – silts and clays up to 100 ft thick found 150 to 200 ft below ground surface; and
- Mahomet Sand – sand and silt that fill the deepest portions of the buried bedrock valley.

Bedrock found immediately beneath the Quaternary deposits consists of upper Pennsylvanian shales, sandstones, limestones, and coals of the Modesto and Carbondale formations (Willman et al. 1967), including the currently mined bituminous coal, which is about 300 ft below the ground surface. Minor subsidence has occurred in some areas located above mined-out portions of the coal seam.

Coal extracted from the Turris Mine occurs in a relatively flat, 4.5 ft to 6.0 ft thick seam at a depth of 250 to 300 ft. The coal is extracted using room-and-pillar mining methods from panels (or blocks) with a size of approximately 4,000 ft by 800 ft. Each panel is mined by removing coal from parallel 20-ft wide cuts, while retaining pillars of unmined coal varying in thickness from 55 ft to 100 ft. Coal pillars at the edges of mined areas underlying land in the vicinity of the proposed plant site typically have 75 ft thickness. Coal recovery generally varies from 35% to 45%. Larger coal barrier pillars with widths of 180 ft to 200 ft are retained between adjoining blocks of mined coal.

Areas of coal beneath the land surface in the vicinity of the site proposed for the power plant were mined in 1983-1984 and 1990 (Chugh 2001). Figure 3.4.2 depicts the anticipated relationship between the proposed site for the power plant, with currently anticipated locations for the steam turbine and exhaust stack, and the underlying schematic of mined-out areas, coal pillars, and barrier pillars.

Surface topography above the mine is flat to gently rolling, with a relief of about 20 ft. Glacial material above the coal seam beneath the project site has a thickness of about 220-230 ft. Rock overburden, consisting primarily of shales, limestones, and sandstones, above the coal has a thickness of 50-70 ft, thus providing an average overburden thickness of about 280-290 ft at the project site.

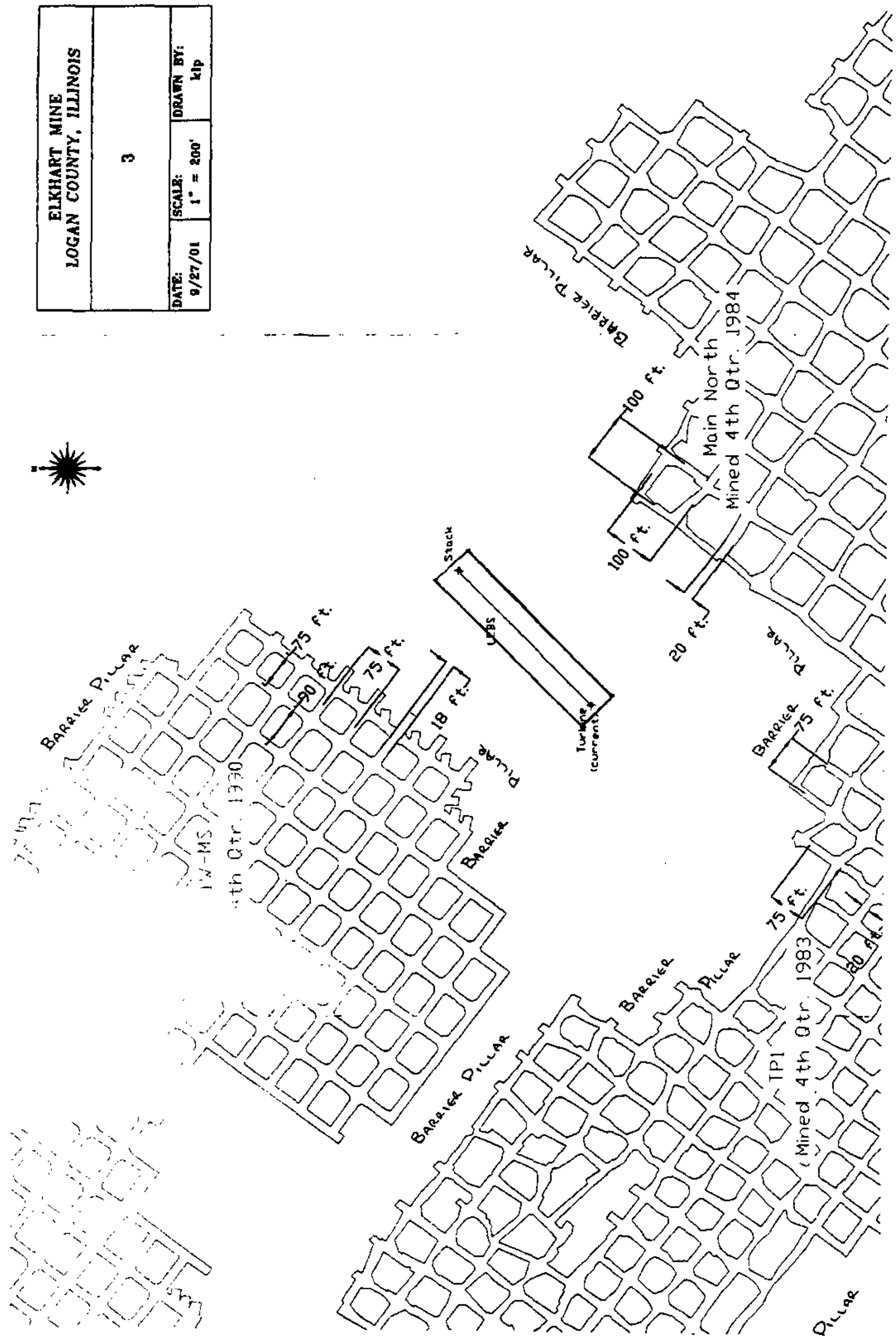

Figure 3.4.2. Location of the proposed power plant in relation to former workings of the Turris Mine

The roof stratum immediately above the coal consists of a weak, thin band of shale with a thickness of 1-8 ft (average 3 ft). Overlying the shale is a limestone bed with a compressive strength of 15,000 psi. The coal is associated with a thick (4-6 ft), weak (200-500 psi compressive strength) claystone floor stratum, which is sensitive to water, based on swelling strain and clay mineral composition. Mined-out areas are thus susceptible to floor heave, deformation, and failure, which can result over time in surface subsidence. Historical information for the Illinois Coal Basin indicates that 1-2 ft of surface subsidence may occur due to floor deformations over areas mined using room-and-pillar methods.

Since mine-out by 1990 of the coal underling the vicinity of the proposed site, no subsidence incidences have been reported in the area of the proposed power plant.

3.4.2 Hydrogeology

Groundwater supplies in Logan County are obtained from unconsolidated sand and gravel *aquifers* developed in glacial drift. Yields from groundwater wells commonly range from 10 to 1,000 gpm but may exceed 3,000 gpm (USGS 1985).

Figure 3.4.1 provides a generalized *hydrogeologic* cross-section showing the aquifers and *aquitards* beneath the Turris Mine site. Two principal aquifers exist: the Pearl Formation and the Mahomet Sand. Under portions of the site, the Pearl Formation and the Kansan Outwash can be considered distinct aquifers because of separation by the Vandalia Till, which is an aquitard. However, under a major part of the site, these features comprise a single aquifer because the Vandalia Till is absent. The municipal water supply for the town of Elkhart is obtained from the Pearl aquifer, while the Turris Mine obtains potable water supply from the Kansan outwash.

In addition to the Pearl Formation and Mahomet Sand aquifers, sand and gravel *lenses* exist in the Hagarstown formation, which also contains groundwater; however, these sand and gravel lenses do not yield sufficient water for residential or agricultural use. *Perched groundwater*, which occurs as a shallow water table near the ground surface in wet weather, is also found in the weathered drift above the relatively impermeable, clayey Sangamon Soil.

Groundwater in the Hagarstown, Pearl, and Mahomet Sand formations appears to be confined, with the confining beds being the weathered drift, the Sangamon Soil, the Teneriffe Silt, the Vandalia Till (where present), and the undifferentiated Kansan Drift. As is typical of glacial drift aquifers, the aquifers at the site appear to be recharged locally by downward vertical leakage through these confining beds, as evidenced by the downward vertical *hydraulic gradients* measured at the site (Rapps 1989; 1993). However, vertical *hydraulic conductivities* in the confining units are much lower than horizontal hydraulic conductivities in the aquifers. Therefore, the bulk of groundwater flow should occur horizontally in the aquifers rather than downward through the confining units.

The Pearl Formation and Kansan Outwash aquifers could conceivably receive infiltration of surface water through the streambed of Lake Fork Creek. The baseline of the water-stage recorder (or gauge) on Lake Fork Creek near Cornland, Illinois, is located at 555 ft above sea level (Wicker, LaTour, and Maurer 1996), which is indicative of the elevation of the streambed and would be the elevation recorded if no flow occurred in the creek. The top of the Pearl Formation is located at an estimated elevation of 555 ft above sea level (Figure 3.4.1). Hence, Lake Fork Creek may be incised to a sufficient depth that hydraulic communication has been established with the underlying confined Pearl Formation and Kansan Outwash aquifers. However, the existence of appreciable infiltration from Lake Fork Creek into the aquifers has not been demonstrated. Aquifer tests conducted as part of the groundwater study for the proposed plant indicate that no interaction exists between Lake Fork Creek and the underlying aquifer.

Figures 3.4.3 and 3.4.4 provide contour maps of the *piezometric surfaces* and groundwater flow directions in the Hagarstown/Teneriffe and Pearl Formations, respectively, based on groundwater level measurements from May 17, 1993, in monitoring wells around the *slurry* impoundment at the Turris Mine. A groundwater "mound" in the Teneriffe/Hagarstown formations trends from southwest to northeast under the slurry impoundment. Groundwater in the Teneriffe/Hagarstown formations appears to flow outward from this mound toward the southeast and northwest. Based on information contained in boring logs around the impoundment, a ridge composed of sands, silts, clays, and gravels of the Hagarstown formation appears to trend from southwest to northeast, corresponding to the groundwater mound. The vertical component of flow between the Teneriffe/Hagarstown and Pearl Formations is a maximum along this Hagarstown ridge and diminishes as a function of distance from the ridge. The groundwater flow pattern in the Pearl Formation appears to be a subdued replica of the flow pattern in the Teneriffe/Hagarstown formation (Rapps 1993).

The Mahomet Sand aquifer, with a thickness ranging from 0 to 30 ft (Rapps 1989), exists beneath the Turris Mine site. *Transmissivity* of the Mahomet Sand ranges from 4,200 to 700,000 gpd/ft. *Permeability* ranges from 250 to 70,000 gpd/ft^2 (Stephenson 1967; Visocky and Schicht 1969). In contrast, the Pearl Formation has a transmissivity of 120 to 200,000 gpd/ft and a permeability of 30 to 4,100 gpd/ft^2. The Mahomet Sand aquifer has been shown to be hydrologically isolated from the overlying Pearl Formation and Kansan Outwash, as evidenced by the integrity of the Kansan Drift in the site area (Rapp 1989).

A testing program was performed at the Turris Mine property to assess the capability of the aquifers in the vicinity of the mine to provide a sufficient quantity of water for the proposed power plant. Eleven sampling holes were drilled in the plant site area; sieve analysis was performed on the formation samples to determine the appropriate well screens; and pumping tests were conducted to estimate yields. The locations of the sampling holes (TH1-01 through TH11-01) are shown on Figure 3.4.5. The screenings focused on subsurface areas containing the thickest sand and gravel deposits. The results of the testing suggested that the development of three wells (TH1-01, TH5-01, and TH9-01) would provide a long-term sustainable yield of approximately 1,250 gpm (Farnsworth 2001).

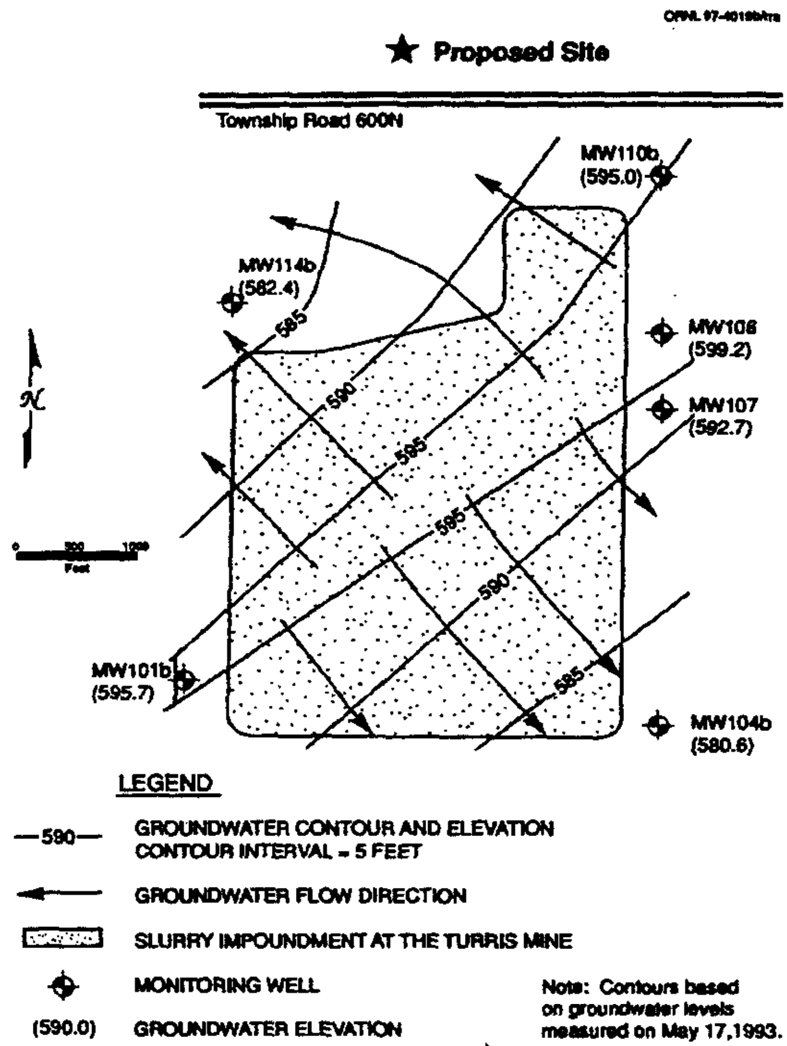

Figure 3.4.3. Piezometric surface elevations and groundwater flow directions in the Hagarstown/Teneriffe Formations below the slurry impoundment at the Turris Mine

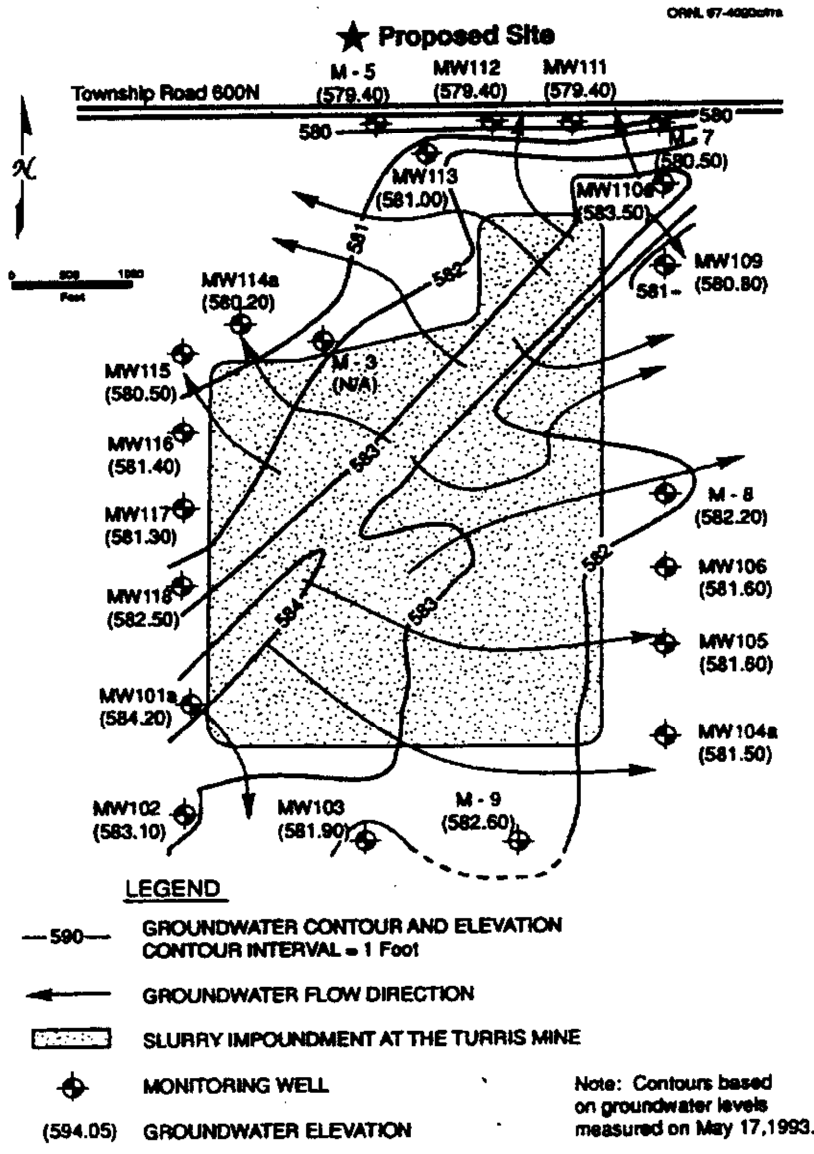

Figure 3.4.4. Piezometric surface elevations and groundwater flow directions in the Pearl Formation below the slurry impoundment at the Turris Mine

3.4.3 Groundwater Quality and Use

Water in the sand and gravel aquifers of Illinois is generally good quality and suitable for most uses. Dissolved solids concentrations range from 360 to 750 mg/L; hardness ranges from about 250 to 510 mg/L as calcium carbonate; and the median concentration of sulfate is about 50 mg/L. Iron concentrations are extremely variable, generally ranging from 50 to 4,000 :g/L (USGS 1988).

Figure 3.4.6 depicts locations of the groundwater supply and monitoring wells being used to assess groundwater quality at the Turris Mine site in relation to the slurry impoundment at the combustion ash disposal area. Average concentrations of selected chemicals identified in quarterly groundwater samples that were collected in 1996 are summarized in Table 3.4.1. Characterization data on water samples from all wells, with the exception of well M8 near the eastern side of the impoundment, indicate that groundwater quality is generally good and has not been adversely affected by mining operations at the Turris Mine site, including the slurry impoundment activities. Dissolved solids, chloride, sulfate, calcium, and magnesium concentrations in well M8, which monitors the Pearl Formation, are higher than the concentrations measured in other on-site wells. None of the other monitoring wells located east of the impoundment, in close proximity to well M8, showed signs of contamination. Well M8 could have intersected a contaminant *plume* seeping from the impoundment into the Pearl Formation, or the annulus around the well casing could have acted as a conduit for seepage due to improper seals. The data from 1996 for well M8 were abnormally high; characterization data from subsequent years have not noted similarly high concentrations.

Groundwater consumption in Logan County ranges from 1 to 10 MM gpd and exceeds surface water consumption by a factor of ten (Section 3.3.2). Groundwater use during 1996 at the Turris Mine was about 33 million gallons, averaging about 90,000 gpd (S. Fowler, Turris Coal Company, personal communication to A. H. Curtis, ORNL, Feb. 21, 1997). All groundwater was obtained from three wells: one potable water well (M11) and two process water wells (the Pole Barn and Exhaust Shaft wells). Groundwater withdrawal by surrounding private and municipal wells was estimated to be approximately 50,000 gpd in 1980 (Harza 1980), and the current withdrawal rate is estimated to be approximately 72,500 gpd.

Figure 3.4.7 shows the locations of all known groundwater supply wells and monitoring wells in the area, including the potable water supply well for the village of Elkhart, based on records from the Illinois State Water Survey's Private Well Database and Public-Industrial-Commercial Database (ISWS 1997a,b). The Elkhart supply well is also part of the monitoring well network at the site; the Elkhart well is designated as M12 on Figures 3.4.5, 3.4.6, and 3.4.7 and in Table 3.4.1.

As part of aquifer testing for the proposed power plant, the water quality of three wells recommended for development as water supply wells for the proposed project was analyzed (Farnsworth 2001). The results are presented in Table 3.4.2.

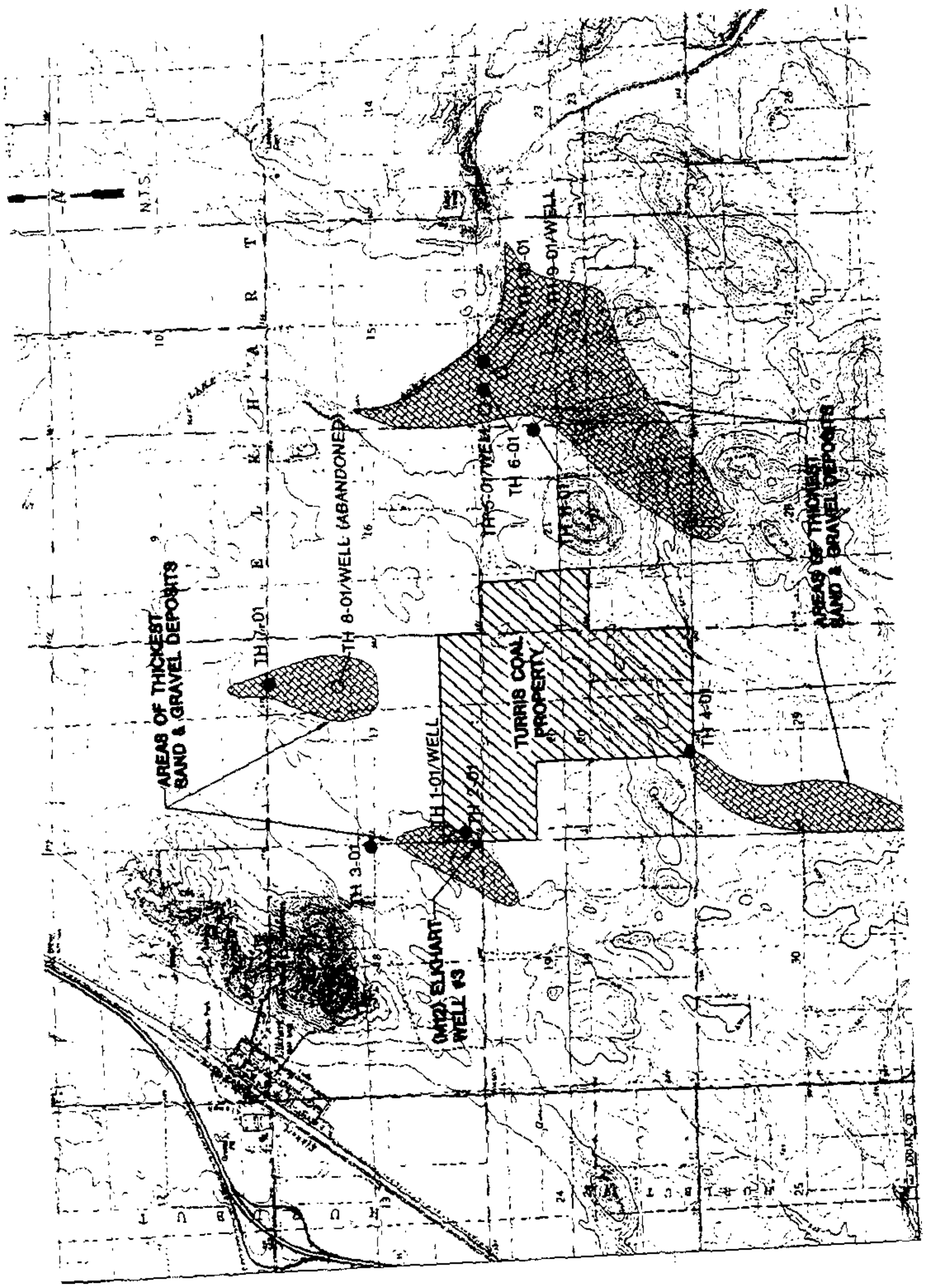

Figure 3.4.5. Locations of groundwater supply test wells TH1-01 through TH11-01 for the LEBS plant

ORNL 97-4017b/rra

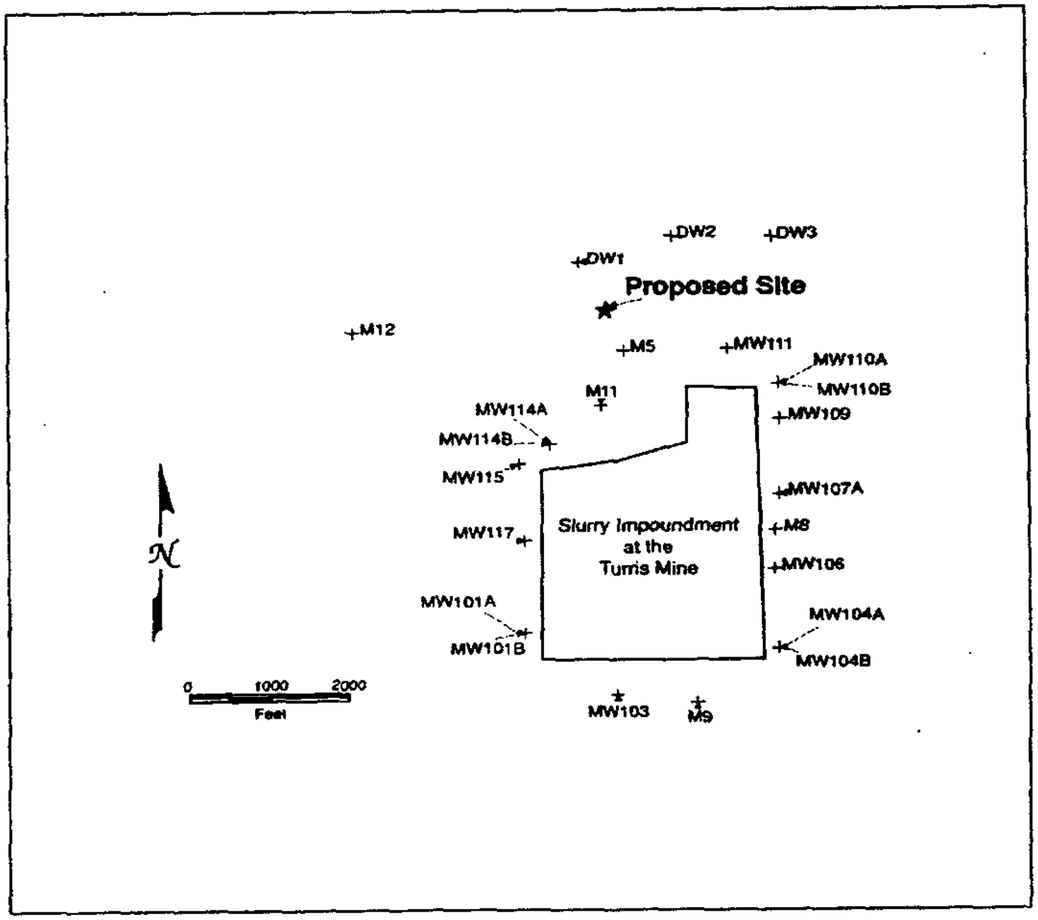

Figure 3.4.6. Locations of groundwater supply wells and monitoring wells used to assess groundwater quality at the Turris Mine

Table 3.4.1. Groundwater quality in 1996 in monitoring wells at the Turris Mine[a]
[Concentrations are averages from quarterly samples]

Well[b]	Parameter[c]										
	pH	TDS (mg/L)	Hardness, (mg/L)	Cl (mg/L)	SO_4 (mg/L)	Ca (mg/L)	Mg (mg/L)	Fe (mg/L)	Mn (mg/L)	Ba (µg/L)	Zn (µg/L)
DW1	7.4	436	379	10.5	20.6	89.8	37.8	42.8	0.18	7.5	<0.05
DW2	7.3	475	404	14.3	20.4	95.3	40.3	42.0	0.08	15	<0.05
DW3	7.1	485	415	12.3	17.0	106.3	36.5	22.3	0.15	12.5	<0.05
MW101A	8.7	302	273	14.3	71.0	59.5	30.3	43.3	<0.01	<0.1	<0.05
MW101B	7.9	385	335	14.8	48.7	76.8	34.3	6.9	<0.01	<0.1	<0.05
MW103	7.3	402	372	5.3	12.0	96.3	32.0	7.4	0.18	<0.1	<0.05
MW104A	7.3	389	357	12.5	49.5	86.3	34.8	3.3	0.13	60	1.9
MW104B	7.7	435	351	30.0	51.5	86.8	32.8	8.4	0.05	<0.1	1.5
MW106	7.4	346	350	7.8	3.1	84.3	34.3	3.4	0.1	<0.1	1.5
MW107A	7.9	326	314	5.3	9.7	71.5	33.0	4.0	0.32	<0.1	1.6
MW109	7.5	351	353	5.3	3.2	77.3	39.0	1.3	0.03	<0.1	<0.05
MW110A	7.3	356	364	3.0	1.0	85.3	36.8	5.4	0.04	<0.1	1.6
MW110B	7.9	382	317	21.8	73.5	73.3	32.8	2.8	<0.01	<0.1	1.3
MW111	7.5	341	338	5.5	1.0	79.3	34.0	7.5	0.2	<0.1	2
MW114A	7.2	370	348	6.5	0.9	85.5	32.8	7.1	0.05	60	<0.05
MW114B	6.9	739	621	22.8	74.5	133.8	70.0	13.3	0.18	60	<0.05
MW115	7.7	335	302	24.5	9.8	76.3	27.0	14.3	0.05	15	<0.05
MW117	7.4	334	312	9.8	10.0	82.0	26.0	1.8	0.03	<0.1	<0.05
M5	7.0	441	392	6.5	17.3	108.5	29.8	17.5	0.09	<0.1	<0.05
M8	7.5	2027	1231	299.0	536.3	268.0	137.0	1.5	0.02	60	<0.05
M9	7.3	359	349	3.5	1.7	85.5	33.3	5.2	0.11	<0.1	<0.05
M11	7.4	419	361	22.3	7.0	90.3	33.0	2.3	<0.01	60	17.4
M12	7.5	422	384	11.3	41.3	96.3	35.0	2.2	0.05	17	<0.05
Drinking water standard	6.5 - 8.5	500	NA	250	250	NA	NA	0.3	0.05	1000	5000

[a] Arsenic, boron, cadmium, lead, mercury, and selenium were also monitored, but all readings were below 1.0 µg/L for arsenic, boron, and lead; below 0.1 µg/L for cadmium; below 0.2 µg/L for mercury; and below 2.0 µg/L for selenium. The drinking water standards, in µg/L, are 50 for arsenic, 1000 for boron, 10 for cadmium, 50 for lead, 2 for mercury, and 10 for selenium.

[b] MW101B, MW104B, MW110B, and MW114B monitor the Teneriffe/Hagarstown Formation; well M11 monitors the Pearl Formation and Kansan Outwash; M12 monitors the Kansan Outwash; and the remainder of the wells monitor the Pearl Formation.

[c] TDS = Total Dissolved Solids; Hardness is measured as $CaCO_3$; Cl = Chloride; SO_4 = Sulfate; Ca = Calcium; Mg = Magnesium; Fe = Iron; Mn = Manganese; Ba = Barium; Zn = Zinc

3.4.4 Soils

Soils at the site proposed for the power plant belong to the Ipava-Sable-Tama association, comprising the Ipava silt *loam*, the Sable silty clay loam, and the Tama silt loam. The Ipava series consists of somewhat poorly drained, nearly level soils on uplands; Sable soils are poorly drained, nearly level soils found mainly on uplands; and Tama soils are well drained, nearly level to strongly sloping soils. These soils developed under grasses in loess (i.e., windblown glacial deposits) more than 60 in. thick, are high in organic matter, and are well-suited for agriculture (Hudelson 1974). The soils have a high erosion hazard (Bergstrom, Piskin, and Follmer 1976), especially on steeper slopes.

3.4.5 Seismic Activity

The proposed site is located in Seismic Zone 1 (SZ1) of the Uniform Building Code (UBC) (ICBO 1994). *Peak ground accelerations* (PGAs) with a 500 year return period range from 0.05 to 0.10 g in SZ1. The UBC recommends a design basis PGA of 0.075 g for ordinary public buildings in SZ1.

No faults are known to exist in the vicinity of the proposed site. Historically, the largest earthquake to occur within 120 miles of the site took place on July 18, 1909, between Havana and Petersburg, Illinois, about 35 miles west-northwest of the site (Stover, Reagor, and Algermissen 1979). The earthquake had a modified Mercalli intensity of VII (estimated magnitude 5.5 to 6.1 on the Richter scale), causing minor damage to structures in Petersburg, Illinois; Davenport, Iowa; and Hannibal, Missouri (Coffman, von Hake, and Stover 1982). Perhaps the greatest potential seismic hazard to the area would come from a recurrence of earthquakes of the type that occurred in 1811-1812 in the active New Madrid seismic zone. Three earthquakes, all of modified Mercalli intensity XII, took place on December 16, 1811, January 23, 1812, and February 7, 1812 (Coffman, von Hake, and Stover 1982). According to Nuttli (1973), the recurrence of an earthquake of this intensity in the New Madrid area would result in intensities between VI and VII in the vicinity of the proposed site, possibly causing minor damage to buildings and other structures in the area.

3.5 SOLID WASTE

The Turris Mine site is a permitted location for disposal of coal combustion wastes from off-site users. Approximately 135,000 tons per year of coal combustion wastes are received for disposal in the 265 acre slurry impoundment. The IEPA and Logan County have the primary regulatory authority for waste management (i.e., disposal) at the site, while the U.S. EPA has regulatory oversight authority.

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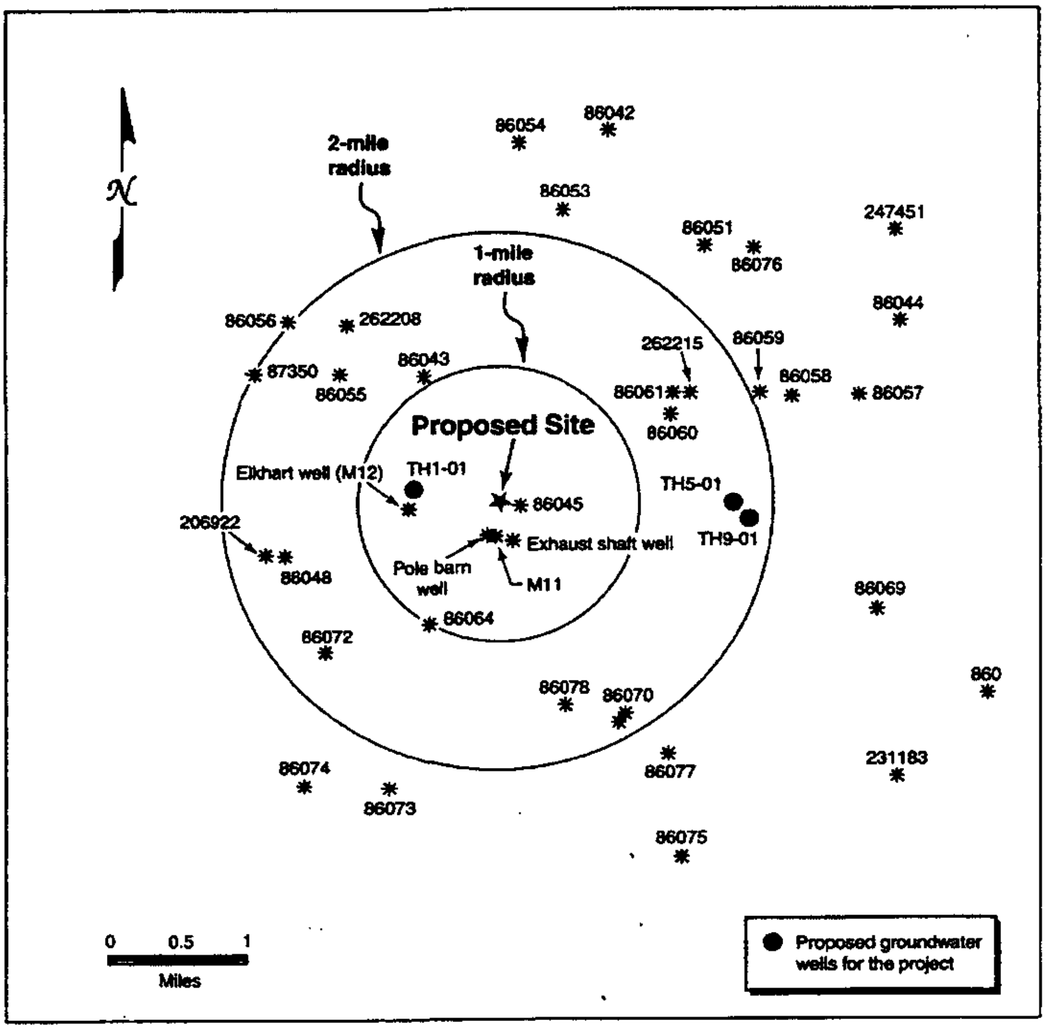

Figure 3.4.7. Locations of groundwater supply wells and monitoring wells in the vicinity of the proposed power plant site. (Basis: records in the Illinois State Water Survey's Private Well Database and Public Industrial-Commercial Database (ISWS 1997a, b))

Table 3.4.2. Water quality results from pumping test investigation (Farnsworth 2001)
(all parameters in mg/L unless otherwise noted)

Parameter	Well TH1-01	Well TH5-01	Well TH9-01
Iron (total Fe)	2.09	2.00	3.31
Manganese	0.13	0.09	0.08
Calcium	74.5	80.0	83.9
Magnesium	33.0	38.6	38.0
Sodium	25.7	12.6	15.0
Aluminum	0.43	<0.03	<0.03
Barium	0.14	0.10	0.08
Boron	0.02	0.02	<0.01
Chromium	<0.004	<0.004	<0.004
Copper	0.01	<0.01	<0.01
Nickel	<0.007	<0.007	0.012
Potassium	22.6	8.4	<6.3
Zinc	<0.01	<0.01	<0.01
Turbidity, NTU[a]	47	21	57
Color, PCU[b]	5	5	5
pH	7.4	7.4	7.4
Odor	None	None	None
Fluoride	0.2	0.2	0.2
Chloride	13.8	16.9	21.9
Nitrate (NO_3-N)	<0.06	3.2	<0.06
Sulfate	18.4	21.4	29.1
Alkalinity ($CaCO_3$)	341	329	372
Hardness (as $CaCO_3$)	322	359	366
Total Dissolved Solids	377	393	427
Non-Volatile Organic Carbon (Total, as C)	0.9	1.0	

[a] Nephelometric Turbidity Units (NTU), as measured using a nephelometer. Acceptable ranges are: 1-5 for human consumption; 5 for recreation; and <50 (instantaneously) or <25 (for 10 day average) for aquatic life.
[b] Platinum Cobalt Units (PCU), a measure of color relative to the color produced by 1 mg platinum per liter.

3.6 ECOLOGICAL RESOURCES

3.6.1 Terrestrial Ecosystems

Other than the Turris Mine's operations, the primary land use in the immediate vicinity of the proposed site (roughly a 2 mile radius, which would include all areas proposed for water supply wells) is agricultural. A typical square mile of land near the site consists of roughly 1 to 2% wooded areas (primarily along fence rows), cultivated fields, and 1 to 3 small farmsteads. Elkhart Hill, a small (about 0.4 square mile) woodland located about 1 mile northwest of the site, is a state-listed natural area. Elkhart Hill is categorized as a *mesic* upland forest and contains an uncommon assemblage of upland plants because of unusual geology and groundwater supply in the area that keeps the woodland more moist than most upland forests (J. Wilker, Illinois DNR, personal communication to M. Bevelhimer, ORNL, Feb. 18, 1997).

Typical wildlife found in the immediate vicinity of the proposed site includes both game and non-game species (B. Cunningham, Illinois DNR, personal communication to M. Bevelhimer, ORNL, Feb. 5, 1997). Game species include white-tailed deer, ringnecked pheasant, quail, rabbits, and squirrels. Non-game species include opossum, raccoons, skunks, rodents, owls, hawks, and small birds (e.g., sparrows, starlings, and robins). Except for birds and small mammals (e.g., rodents and shrews), wildlife population densities on the site are relatively low. Populations of larger animals are probably higher in areas surrounding the mine, particularly near wooded areas and along streams. The wildlife habitat surrounding the mine property undergoes appreciable seasonal perturbations when crops are harvested and fields are cultivated. Ideal wildlife habitat for most species is not abundant in the area and populations would likely be much greater in less disturbed grasslands and forests. No threatened or endangered species are known to exist in the project area (Section 3.6.3). In summary, the site does not support any particularly unusual or unique vegetation or wildlife, although populations of game species do exist in the surrounding area.

3.6.2 Aquatic Ecosystems

Ponds on the Turris Mine's property were constructed for use in the treatment of wastes from the coal mining operations and for collection of runoff, which is recycled for use in on-site operations. The largest pond on the site (Figure 3.3.3; slurry pond) receives slurry from the coal processing operation and provides little, if any, habitat for plant or animal species. The second largest pond (freshwater pond), located on the northwest corner of the property, stores runoff that is used in coal processing operations; this pond may be used occasionally by waterfowl and other wildlife. During the rare events in which water is discharged from the ponds (Section 3.3.2), the discharge is received by an unnamed tributary of Lake Fork Creek, which is unlikely to provide any aquatic habitat of significance. Lake Fork Creek is a typical Midwestern warm water stream and contains species that are representative of such systems (i.e., primarily various sunfish and minnow species).

3.6.3 Threatened and Endangered Species

The U.S. Fish and Wildlife Service (FWS) lists two mammals, three birds, one fish, six clams, one snail, two insects, and nine plants as threatened or endangered species in Illinois (FWS 1997). Neither any of these species nor any candidate species are known to exist in areas potentially affected by the proposed power plant. The FWS indicated (Appendix A) that the endangered Indiana bat could potentially occur throughout the State of Illinois. Habitat requirements for the Indiana bat consist of caves, abandoned mines, or forest areas providing at least 15% cover. The areas potentially affected by the power plant project, including the plant site, retention pond, and well field, do not provide habitat that would support the Indiana bat. One plant species (the ear-leafed foxglove, *Tomanthera auriculata*) is the only state-listed threatened or endangered species in Logan County but is not found in the vicinity of the site (J. Wilker, Illinois DNR, personal communication to M. Bevelhimer, ORNL, Feb. 18, 1997).

As required under Section 7 of the Endangered Species Act of 1973 (Public Law 93–205, as amended), DOE consulted with the FWS to ensure that the proposed plant would not adversely affect Federally listed endangered or threatened species or result in the destruction or adverse modification of the critical habitat of such species. Appendix A documents the results of consultation with the FWS.

3.6.4 Biodiversity

The biodiversity of an ecosystem or community is defined by the variety or richness of the natural biotic environment (e.g., the number of habitat types or species). The entire Turris Mine property has been disturbed by human activities (i.e., agricultural and mining operations), and the numbers of plant and animal species present at the site proposed for the plant are quite low relative to natural grasslands and forests typical of this region. The biodiversity within a 5 mile radius of the site is somewhat higher but, as a result of extensive agricultural practices, is still far below that found in less disturbed areas.

3.7 CULTURAL RESOURCES

A Phase I cultural resources survey, which comprises an archaeological reconnaissance survey to locate, identify, and record all archaeological resources within the area (IHPA 1998), identified no properties eligible for inclusion on the *National Register of Historic Places*. Nine *National Register* sites are listed in Logan County (NPS 1997), with the closest one to the plant site (the Mount Pulaski Courthouse) being more than 8 miles away. The Phase I cultural resources survey also showed that only a portion of the site is undisturbed and that the site does not contain any archaeological resources. The survey concluded that no further investigations appeared to be warranted.

As required under Section 106 of the National Historic Preservation Act (Public Law 89–665, as amended), DOE consulted with the Illinois Historic Preservation Agency to ensure compliance with the act. Appendix B documents the results of the consultation.

3.8 FLOODPLAINS AND WETLANDS

The proposed plant site, with an approximate elevation of 585 ft (Beittel and Darguzas 1996), is located in an upland area that has been determined to be outside of the 500 year *floodplain*

(FEMA 1988a) and therefore outside the 100 year floodplain. A flood of record resulted from a series of intense storms centered over the State of Illinois between May 6 and 24, 1943 (Zuehls and Wendland 1991). Many gauging stations in the Kaskaskia, Embarras, Sangamon, Vermilion[1], and lower Illinois River basins recorded streamflows in May 1943 that are the maxima of record. Recurrence interval estimates for the 1943 central Illinois flood, including Lake Fork Creek, range from 50 to more than 100 years.

The May 1943 flood on Lake Fork Creek near Cornland reached a stage of 23.4 ft (Wicker, LaTour, and Mauer 1996), corresponding to an elevation of 578.5 ft. The instantaneous peak stage and water surface elevations measured in the 1948 to 1995 period of record were 23.1 ft and 578.2 ft, respectively, both of which occurred on April 12, 1979.

The extreme northwestern corner of the permit area occupied by the Turris Mine lies within a special flood hazard area that would be inundated by a 100 year flood. No base flood elevations have been determined for that area.

Aerial photographs of the area around the proposed plant site and information from a groundwater survey conducted through a grant with the Illinois Department of Commerce and Community Affairs (Farnsworth Group 2001) indicate that no *wetland* areas exist within 1 mile of the site, except for the ponds on the Turris Mine property (which have little or no ecological significance). Consultation with the U.S. Army Corps of Engineers confirmed that no jurisdictional wetlands exist at the site.

3.9 SOCIOECONOMICS

The potential impact area for the proposed power plant consists of Elkhart, Illinois, (the closest town to the site) and Logan County, in which Elkhart and the proposed site are located. This section focuses on those socioeconomic resources that could be affected by the proposed plant – population, employment and income, housing, and selected public services.

3.9.1 Population

Table 3.9.1 presents the 2000 census counts for areas of potential impact and data illustrating changes in the number of residents since 1980. The town of Elkhart had a population of 443 in 2000, a 6.7% decrease since 1990. Logan County, with a population of 31,183 in 2000, has grown by 1.3% since 1990 but has slightly fewer residents than in 1980. The city of Lincoln, which is about 10 miles from the plant site, accounts for about half the county's residents, but its population has declined slightly since 1990.

[1]Tributary to the Wabash River – a tributary to the Illinois River has the same name.

Table 3.9.1. Population change over time in the impact area of the proposed power plant

Location	1980 population	1990 population	Percent change 1980–1990	2000 population	Percent change 1990–2000
Logan County	31,802	30,798	-3.2	31,183	1.3
Elkhart	—	475	—	443	-6.7
Lincoln	16,327	15,418	-5.6	15,369	-0.3
Illinois	11,427,409	11,430,602	0.03	12,419,293	8.7

Sources: U.S. Census Bureau 1980, 1997a, 1997b, and 2000.

3.9.2 Employment and Income

In the year 2000, the total civilian labor force residing in Logan County was reported as 14,167, of which 13,656 were identified as being employed and 511 unemployed. The unemployment rate of 3.6% in Logan County was less than the 4.4% rate for the State of Illinois (Illinois Department of Employment Security 2001). The latest available data for the village of Elkhart are from 1990, at which time a civilian labor force of 251 and an unemployment rate of only 2.4% were reported (U.S. Census Bureau 1994).

Table 3.9.2 lists the breakdown of employment by economic sector for those workers employed in Logan County in 1997, the latest year for which complete data are available. As shown, the greatest numbers of jobs were in services (37.3%), retail trade (18.0%), manufacturing (10.8%), agriculture (10.4%), and government (9.1%).

In 1998, average per capita income in Logan County was $19,358, which was 65% of the state average of $29,853 and 71% of the national average of $27,203 (U.S. Bureau of Economic Analysis 1998). In 1989, the latest year for which data are available, Elkhart had an average per capita income of $12,096 (U.S. Census Bureau 1990).

Table 3.9.2. Employment by economic sector for Logan County, Illinois

Economic sector	Number of workers	Percent of total workers
Agriculture	1,439	10.4
Mining	225	1.6
Construction	183	1.3
Manufacturing	1,490	10.8
Transportation and public utilities	523	3.8
Wholesale trade	507	3.7
Retail trade	2,481	18.0
Finance, insurance and real estate	549	4.0
Services	5,139	37.3
Government	1,248	9.1
Total	13,784	100.0

Source: T. Hamrick, Illinois Department of Commerce and Community Affairs, personal communication to M. Schweitzer, ORNL, July 16, 1997.

3.9.3 Housing

Table 3.9.3 presents housing information in the area of potential impact of the proposed plant. The number of occupied housing units in Logan County increased from 11,033 in 1990 to 11,113 in 2000, while vacant units increased from 605 to 759. The rental vacancy rate, which increased from 4.0% to 6.0%, was considerably higher than the homeowner vacancy rate (1.6% in 1990 and 1.9% in 2000). In Elkhart, only 11 vacant units existed. The homeowner vacancy rate in Elkhart decreased from 3.4% in 1990 to 0.6% in 2000, while the rental vacancies increased from 0.0% to 6.3%.

Table 3.9.3. Housing data for Logan County and Elkhart, Illinois

	Logan County		Elkhart	
	1990	2000	1990	2000
Total number of housing units	11,638	11,872	192	194
Number of occupied housing units	11,033	11,113	179	183
Units occupied by owner (%)	67.8	71.3	78.8	83.6
Units occupied by renter (%)	32.2	28.7	21.2	16.4
Number of vacant housing units	605	759	13	11
Homeowner vacancy rate (%)	1.6	1.9	3.4	0.6
Rental vacancy rate (%)	4.0	6.0	0.0	6.3
Median value owner-occupied unit ($)	48,700	75,700	48,500	68,300
Median rent ($)	223	455	228	478

Source: U.S. Census Bureau 1990, 2000.

3.9.4 Public Services

Three municipalities in Logan County have centralized water and sewer systems (Atlanta, Lincoln, and Mount Pulaski) and ten towns have centralized water systems (Beason, Broadwell, Chestnut, Elkhart, Emden, Hartsburg, Latham, Middletown, New Holland, and San Jose). In areas of the county that are not served by centralized systems, water is obtained from individual wells (typically between 30 and 100 ft deep) and waste water disposal is achieved using individual septic systems. The county health department periodically inspects existing septic systems and neighboring wells and may require the use of aeration tanks if percolation is not adequate (R. Menzies, Director, Logan County Regional Planning Commission, personal communication to M. Schweitzer, ORNL, April 19, 2001).

Information about Logan County's seven public school districts is provided in Table 3.9.4. Students from the Atlanta area, although residents of Logan County, attend schools that are in the Olympia School District in neighboring McLean County. In addition to the public schools, five parochial schools are operated in the county, with three serving kindergarten through 8th grade and two serving kindergarten through 12th grade. Also, Lincoln College and Lincoln Christian College are located in the county, as is a branch of Heartland Community College (S. Blane, Regional Office of Education, personal communication to M. Schweitzer, ORNL, July 17, 1997).

Table 3.9.4. Public school districts in Logan County, Illinois

School district	Grades served	Number of schools
Chester–East Lincoln District 61	K–8	1
Hartsburg–Emden District 21	K–12	2
Lincoln Community High School District 404	9–12	1
Lincoln Elementary School District 27	K–8	6
Mount Pulaski District 23	K–12	3
New Holland–Middletown District 88	K–8	2
West Lincoln–Broadwell Elementary District 92	K–8	1

Source: S. Blane, Regional Office of Education, personal communication to M. Schweitzer, ORNL, July 17, 1997.

3.10 HUMAN HEALTH AND SAFETY

The existing health and safety environment in the vicinity of the proposed plant is substantially defined by operations at the adjacent Turris Mine. Turris Coal Company, which operates the Turris Mine, maintains an occupational injury index that is below the national average. The Turris Mine has been recognized by the Illinois Coal Association and the Illinois Department of Natural Resources for mining operations with the lowest reportable accident frequency rate per employee-hours worked.

3.11 NOISE

The noise environment in the immediate vicinity of the proposed plant is dominated by operation of the Turris Mine and transportation of coal from the facility. A few residences are located about 4,000 ft from the coal mine boundaries, and these homes experience the relatively quiet noise environment of a rural setting. Vehicular traffic provides the majority of noise for these residences. Noise levels have not been measured, but they are anticipated to be in the range of 35-45 dB(A) in the Day-Night Level metric (FICON 1992).

3.12 TRAFFIC

The proposed plant site, which is located about 3 miles southeast of Interstate 55, would be accessed via Township Road 600N, a two lane blacktop road that runs east-west. Township Road 600N is a heavy duty road that was constructed by the Turris Coal Company in 1982 to handle mine-related traffic, mostly heavy trucks. The road is 24 ft wide and has shoulders (R. Fox, Logan County Highway Engineer, personal communication to M. Schweitzer, ORNL, July 17, 1997). In 1998, the Turris Coal Company repaved Township Road 600N between the mine entrance and Old Route 66, which is adjacent to I-55.

Very little traffic that is not related to mine activities uses Township Road 600N. At present, a maximum of 800 daily trips on Township Road 600N are made by coal-carrying trucks; this truck traffic is spread over a 24 hour period, with approximately two-thirds of the traffic occurring during daytime hours. In addition to the truck traffic, approximately 30 mine employees use the road daily. Worker traffic is spread over three shifts, with roughly half of the employees working the day shift. Routine deliveries to the mine necessitate an additional traffic load of approximately 25 vehicles per day. A traffic light is installed on Township Road 600N at the entrance to the mine property to provide a red blinker for vehicles leaving the mine and a yellow blinker for road traffic (W. Schultz, Manager of Surface Engineering, Turris Coal Company, personal communication to M. Schweitzer, ORNL, April 12, 2001). When a much larger workforce (approximately 240 employees) used Township Road 600N to access the site daily, no congestion was reported at the mine entrance, even during shift changes (S. Fowler, former Manager of Engineering, Turris Coal Company, personal communication to M. Schweitzer, ORNL, July 17, 1997).

On infrequent occasions (roughly twice a month), empty coal trucks arriving at the Turris property to be loaded cannot gain immediate access to the site, due to the presence of other trucks, and must wait on the shoulder of Township Road 600N – usually on the south side. Typically, no more than six trucks are involved, and the waiting period lasts roughly 30 minutes to one hour. This situation does not interfere with the flow of traffic on Township Road 600N (W. Schultz, Manager of Surface Engineering, Turris Coal Company, personal communication to M. Schweitzer, ORNL, April 12, 2001).

3.13 LAND USE

The proposed plant would be located on the Turris Mine property, which occupies a land area of approximately 750 acres and is located about 2 miles southeast of the town of Elkhart in Elkhart Township, Logan County, Illinois (Beittel and Darguzas 1996). The Turris Coal Company has a permit that allows coal mining, coal preparation, and disposal of coal combustion wastes on the property, and 480 acres have been developed and committed to a variety of land uses, including buildings, roads, parking lots, coal storage piles and silos, a truck loading terminal, coal conveyors, and waste disposal ponds. The remaining 270 acres are either leased for crop production or unused, partially covered with weedy vegetation in disturbed areas, and interspersed with some small scattered brush and shrubs.

The agricultural area surrounding the Turris Mine is used primarily for corn and soybean production. A few single family dwellings and light industries related to agricultural production exist in the area. Small woodlands are situated in lowland areas along drainageways, while upland areas are primarily used to grow crops and graze livestock.

Surface operations of underground coal mines are exempt from prime farmland designation. The Farmland Protection Policy Act of 1981 (7 USC 4201 et seq.; 7 CFR 658) states that the designation *prime farmland* does not include land already (i.e., before 1981) in or committed to urban development. Because construction of the Turris Mine began on October 1, 1980 (HEI 1998), the decision to allocate agricultural land for the mining of coal was made prior to the legislation. Approximately 270 acres of the property owned by Turris Coal Company are leased to local farmers for agricultural use.

Corn Belt Energy Corporation has worked with Logan County, the City of Lincoln, and the Elkhart Village Board, to secure approval for an enterprise zone for the Corn Belt Project, which would include the Turris Mine. Both the Mayor of Elkhart and the Logan County Planning and Zoning Commission have cooperated on site plan approval for the enterprise zone.

Elkhart Hill is a prominent local landmark located approximately 1 mile northwest of the proposed project site. Elkhart Hill is densely wooded, provides habitat for deer, is a residential area, and is the location of Elkhart cemetery. Railsplitter State Park is located about 8 miles the north of the plant site (USGS 1980a).

3.14 ENVIRONMENTAL JUSTICE

Executive Order 12898, issued in February 1994, requires that Federal agencies consider environmental justice in their programs, policies, and actions. Environmental justice is defined as the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Fair treatment means that no groups of people, including racial, ethnic, or socioeconomic groups, should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of Federal, state, local, and tribal programs and policies (EPA 1995a).

A potential for environmental justice impacts would exist if the percentage of minorities or low-income households in close proximity to a project that produces adverse environmental effects substantially exceeds county or state averages. Table 3.14.1 presents ethnicity data from the 2000 U.S. Census for residents of Elkhart, Logan County, and the State of Illinois. The table clearly shows that the percentage of minorities in Elkhart – the town closest to the proposed plant site – is much lower than the county or state averages. In addition, the percentage of Elkhart's residents living below the poverty level (6.7%) is appreciably less than that for the residents of Logan County (11.6%) and Illinois (11.3%) (U.S. Census Bureau 1994 and 1999b).

Table 3.14.1. Comparative ethnicity, by percentage of population, for environmental justice screening purposes

Ethnicity	Elkhart	Logan County	Illinois
Black or African American	0.5	6.6	15.1
Hispanic	0	1.6	12.3
Asian	0.2	0.5	3.4
American Indian and Alaska Native	0	0.2	0.2
Some Other Race	0	0.4	5.8
Two or More Races	0	0.6	1.9

Source: U.S. Census Bureau 2000.

4.0 ENVIRONMENTAL CONSEQUENCES

4.1 AESTHETICS

Construction of the proposed power plant would produce minor short-term visual impacts related to increased activity in the area, including delivery of construction equipment and supplies, site preparation and construction work, and transit of construction workers to and from the site. Because the roads that would be used are paved, fugitive particulate emissions from vehicles traveling on the roads would be minimized. Although the amount of land that would be disturbed for the proposed plant is relatively small (approximately 5 acres), some fugitive dust associated with site preparation may be visible within a few miles of the site, particularly during dry periods with strong winds when loosened earth would be lifted and transported. However, fugitive dust would be minimized by wetting the construction area with water. Minimal vegetation would be removed during construction.

The physical presence of new facilities for the plant, such as the boiler stack and transmission lines, would not cause a major degradation to the visual characteristics at the site. The new facilities would be consistent in character with the existing viewing landscape, which includes industrial buildings, coal storage silos (257 ft height), coal piles, coal conveyors, refuse disposal ponds surrounded by earthen berms, and electric transmission lines and towers. The boiler stack (293 ft height) would be comparable in scale to the existing coal storage silos and would not represent a major visual intrusion on the current appearance of the overall site.

Mining operations at the Turris Mine to accommodate operation of the proposed power plant would not appreciably change. Work would continue to be performed under the existing permit for surface impacts from underground coal mining.

Air emissions from the boiler stack, as a result of physical and chemical processes, would have the potential to cause a plume that would be visible to human observers. Directly emitted particulate matter can scatter light. NO_x emissions are chemically converted in the atmosphere to NO_2, a reddish-brown gas that absorbs light, and SO_2 emissions can be converted in the atmosphere to sulfate particles that scatter light. The combined effects of all emissions, in some cases, can result in a power plant plume that might be slightly visible upon exiting the stack or within a few miles downwind. However, because the technologies that would be incorporated into the proposed plant would be expected to capture at least 96% of SO_2 emissions, decrease NO_x emissions by 85%, and remove 99.8% of particulate matter from a relatively small power plant generating 91 MW of electricity, any visible plume of air emissions from the proposed plant should barely be noticeable. No scenic vistas, which could potentially be adversely affected in the event that a visible plume would be created, exist in the vicinity of the proposed project.

During stable atmospheric conditions with light winds and cool temperatures, a plume of condensed water vapor rising from the cooling tower would be visible, and a condensation plume of water droplets may also be visible from the boiler stack. Even under extremely cold and stable conditions, however, the plumes of water droplets would be expected to evaporate within a few miles of the site.

In summary, visual characteristics at the site would not be altered appreciably over the long term from those that presently exist because (1) the proposed site for the power plant would be located adjacent to an area that has experienced prior human disturbance and industrial development; (2) the land area that would be disturbed for the proposed plant would be relatively small; (3) only a small amount of grassy vegetation would be disturbed; (4) the physical structures to be constructed would be similar to existing facilities at the adjacent Turris Mine; (5) electricity generated by the proposed power plant would be exported from the existing substation at the site using existing transmission lines; (6) plumes of air emissions from the proposed plant should barely be visible and infrequent condensation plumes should evaporate within a few miles of the site; and (7) other land use in the area surrounding the proposed project site is primarily agricultural with no scenic vistas or aesthetic landscapes.

4.2 ATMOSPHERIC RESOURCES

The following sections present the potential air quality impacts that could result from construction and operation of the proposed power plant. The significance of impacts is presented in relationship to criteria that have been established for protection of public health and welfare and the environment.

4.2.1 Construction

During construction, temporary and localized increases in atmospheric concentrations of nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and particulate matter would result from the exhausts of workers' vehicles, heavy construction equipment, diesel generators, and other machinery and tools. Construction vehicles and machinery would be equipped with standard pollution control devices to minimize emissions, which would be very small compared to regulatory thresholds typically used to establish requirements for air quality impact analysis.

Fugitive dust would result from excavation and earthwork. The impacts of this dust on off-site ambient air concentrations of particulate matter were modeled using the EPA-recommended Industrial Source Complex Short-Term (ISCST3) air dispersion model (EPA 1995b) with Plume Rise Model Enhancements (ISC-Prime). An average emission factor of 1.2 tons of total suspended particulate matter per acre per month (EPA 1985) was assumed to result from site construction activities, with 30% of the mass expected to consist of particles less than 10 μm in diameter (PM_{10}) (Kinsey and Cowherd 1992). The maximum land area disturbed at any one time was assumed to be 7 acres. Application of water from the existing fresh water pond at the Turris Mine was assumed as a standard practice for dust suppression, which would reduce fugitive dust by 50% (EPA 1985), and construction activities would be performed during daylight working hours.

Meteorological data from Springfield, Illinois, in conjunction with corresponding upper-air data from Peoria for the year 1991, were used for the screening analysis of construction impacts. Springfield is the nearest location at which quality-assured hourly meteorological data are archived. Because the terrain in central Illinois is relatively flat and homogeneous, meteorological data at Springfield would be representative of conditions at the site of the proposed power plant. The Peoria site provides the nearest upper-air data, which represent large-scale meteorological conditions and are relatively uniform over large regions, especially where the terrain is relatively flat. Therefore, upper-air data from Peoria would be representative of upper-air conditions at the plant site. Because pollutant concentrations from ground-level releases of fugitive dust decrease with distance from the source, concentrations were modeled at a circular grid of receptor locations near the edge of the proposed construction area (where maximum concentrations would be expected to occur) and not at more distant locations.

Results for the sum of modeled concentrations from project construction and the ambient background concentration (Table 3.2.1) indicated that no exceedances of the NAAQS for 24-hour averaged PM_{10} would be expected beyond about 300 ft from the edge of the construction area. Results for annual averaged PM_{10} indicated that the sum of modeled and background concentrations would be less than 70% of the corresponding NAAQS at 300 ft from the edge of the construction area. However, since modeling for the annual averaged PM_{10} concentration assumed continuous earthwork for a full year, which would not occur, the annual averaged PM_{10} concentration would be less than predicted by the model.

4.2.2 Operation

4.2.2.1 Ambient Air Quality Impacts from Criteria Pollutant Emissions

Prevention of Significant Deterioration (PSD)

PSD increments would provide indications of the potential for the proposed plant to affect human health and the environment. As noted in Section 3.2.2, the nearest PSD Class I area, for which the allowable degradation of air quality is severely restricted, is Mingo Wilderness Area, located about 210 miles south-southwest of the proposed plant site. Although PSD analysis is not required for Class I areas beyond 60 miles from an emission source, modeling results indicated that emissions from the proposed power plant would have little, if any, effect on pollutant concentrations in the ambient air. Further, winds in the vicinity of Elkhart (Figure 3.2.1) would usually transport pollutants in directions that would not affect the Mingo Wilderness Area. Therefore, the following analysis focuses on maximum allowable increments for PSD Class II areas.

Emissions of air pollutants from the proposed power plant would be discharged primarily through the combustion boiler stack. Other potential pollution sources during operation would include plant vehicular traffic and personal commuter vehicles; however, the small volume of traffic associated with plant operation would not contribute appreciably to ambient-air pollutant concentrations in the area and therefore was not included in the emission totals for the PSD modeling analysis.

Potential air quality impacts of emissions from the boiler stack at the proposed power plant were evaluated using the ISC-Prime air dispersion model. Effects of downwash, which would reduce the rise in elevation of a plume due to aerodynamic effects of buildings or other structures near a stack, were included in the modeling. The following stack values were used as input parameters for air quality impact modeling: stack height of 89.3 meters (293 ft), diameter of 2.04 meters (6.7 ft), exit temperature of 322°Kelvin (49°C or 120°F), and exit velocity of 15.23 meters per second (50 ft per second). Model input included five years (1987-1991) of hourly meteorological data from Springfield, augmented by corresponding (twice daily) upper-air data from Peoria.

Concentrations were modeled at each point (receptor) on two receptor grids that were developed by Harza (2001). A fine receptor grid covered a 0.6 × 0.6 mile area centered at the site of the proposed power plant; receptors within this grid are located at 330 ft intervals. A coarse grid surrounding the site of the proposed power plant would cover a 6 ×6 mile area with receptors at 1,640 ft intervals. The nested grids allow both a relatively intense analysis near the site of the proposed plant and a more general analysis of air quality in the region.

PSD increments have been established for SO_2, NO_2, and PM_{10} (Section 3.2.2). For short-term (3 hour and 24 hour) averaging periods, the PSD requirements allow for one anomalous exceedance of the standards per year (40 CFR 51.166); therefore the highest modeled 3 hour and 24 hour concentrations at each receptor location for each year were excluded, and the highest remaining values resulting from application of the 5 years of meteorological data were used. The analysis shows that modeled concentrations would always be less than 30% of the allowable PSD increments (Table 4.2.1).

Table 4.2.1. Prevention of Significant Deterioration (PSD) impact analysis for the proposed power plant at Elkhart, Illinois

Pollutant	Averaging period	PSD Class II increment[a] (μg/m³)	Modeled concentration increase (μg/m³)	Location of maximum concentration increase[d]	Percentage of PSD Class II increment
SO_2	3 hour	512	91[b]	0.6 mi E	18
	24 hour	91	25[b]	1.4 mi WNW	27
	Annual	20	2[c]	0.6 mi ENE	10
NO_2	Annual	25	1[c]	0.6 mi ENE	4
PM_{10}	24 hour	30	2[b]	0.1 mi SE	7
	Annual	17	0.3[c]	0.1 mi SSE	2

[a]PSD increments are standards established in accordance with the Clean Air Act provisions to limit the degradation of ambient air quality in areas that have attained the National Ambient Air Quality Standards.

[b]For averaging periods less than one year, one exceedance per year is allowed (40 CFR 51.166); therefore, the highest modeled concentration for each year has been excluded, and the highest of the remaining concentrations over the 5-year modeling period is listed.

[c]Maximum modeled annual concentration.

[d]Miles and direction from boiler stack.

A detailed PSD analysis for regulatory applications may consider other sources in the area (as determined from 40 CFR 51.166) that are potentially contributing to the degradation of air quality. Emissions of NO_2 and PM_{10} from other sources in the region are more than 10 times the emissions that would be expected from the proposed power plant; therefore, emissions from those other sources resulted in appreciable increases in modeled concentrations, especially at locations close to those sources. For example, near Decatur (about 25 miles east-southeast of the plant site), where other PSD sources are dominant, concentrations were modeled to be about 35% of the PM_{10} increments and slightly above 20% of the NO_2 increment. However, modeled contributions from the proposed plant were minuscule at that location.

A detailed PSD analysis, including the cumulative effects of the proposed plant and other sources in the region, has been performed for SO_2 and summarized in the PSD permit application (Harza 2001); the results indicate that no violations of PSD increments for SO_2 would be expected. Because modeling of NO_x and PM_{10} emissions from the proposed power plant resulted in maximum concentration impacts that were substantially less than their respective significant impact levels, additional PSD modeling of NO_x and PM_{10} emissions from the proposed power plant in combination with emissions from other sources in the region was not required.

Following analysis of the PSD permit application (Harza 2001), the Illinois Division of Air Pollution Control issued a draft permit on June 17, 2002, for public review. The public review process included a public hearing on August 1, 2002, in Elkhart, IL, during which all commenters either supported the proposed project or provided inquiries regarding project schedules or possible employment opportunities. The Division of Air Pollution Control issued a construction permit for the proposed power plant on December 17, 2002. A copy of the permit is provided in Appendix D.

National Ambient Air Quality Standards

Pollutants for which National Ambient Air Quality Standards (NAAQS) exist (criteria pollutants) include SO_2, NO_2, CO, O_3, Pb, and two size classes of particulate matter (PM_{10} and $PM_{2.5}$). The ambient air concentrations of CO are primary concerns near major intersections in large cities, where many vehicles are concentrated within a relatively compact geographic location and where idling and air circulation is limited by surrounding high-rise buildings. The ambient CO concentrations in the Elkhart area are less than 30% of the 8 hour NAAQS (ambient level of 2,760 $\mu g/m^3$ compared with a standard of 10,000 $\mu g/m^3$) and less than 20% of the 1 hour NAAQS (ambient level of 7,360 $\mu g/m^3$ compared with a standard of 40,000 $\mu g/m^3$) (Table 3.2.1). Because the emission rate of CO from the proposed power plant would be less than 80% of the emission rate for SO_2 (Table 2.1.1), which resulted in modeled maximum increases in SO_2 of only hundreds of $\mu g/m^3$ in ground concentrations, the CO emissions from the power plant would not be expected to increase ambient air CO concentrations to levels that would exceed (or even approach) the NAAQS. Therefore, CO emissions from the proposed plant were not evaluated further.

No appreciable Pb emissions would be expected from construction or operation of the proposed power plant. Ambient air concentrations of Pb in recent years have been well below the NAAQS (Table 3.2.1), largely as a result of decreased use of leaded gasoline in automobiles.

The standards for $PM_{2.5}$ have only recently been established (62 *FR* 138) and have not yet been fully implemented. Ambient air concentration data for comparison with the $PM_{2.5}$ standards, which apply to 3 year averages, are not yet available.

Impacts of O_3 expected to result from operation of the proposed power plant are discussed as regional-scale impacts in Section 4.2.2.2.

The remaining analyses in this section address the potential impacts that would result from emissions of SO_2, NO_2, and PM_{10}.

Potential cumulative impacts on air quality were evaluated by using an air dispersion model to estimate the maximum increases in ground-level concentrations of pollutants resulting from the combined emissions of the proposed power plant and other regional sources (PSD sources and non-PSD sources). The modeled maximum ground level concentration was added to measured background (ambient air) concentrations (Table 3.2.1) and compared to NAAQS limits. Consistent with the PSD analysis, the ISC-Prime air dispersion model was used for estimating pollutant concentrations, and 5 years (1987-91) of meteorological data were used.

Pollutant concentrations were modeled for the same two receptor grids (0.6 × 0.6 mile and 6 × 6 mile) used for the PSD analysis. For PM_{10}, however, the grid did not include receptors within 3,000 ft of the Turris Mine. Although PM_{10} concentrations may be high at locations near the Turris Mine, members of the general public would not receive extended exposures at those locations because the nearest residences are located about 4,000 ft from the mine boundary (Section 3.11).

Maximum pollutant concentrations resulting from operation of the power plant in conjunction with pollutant concentration resulting from emissions from other existing sources within 30 miles are presented in Table 4.2.2. Because modeled contributions of emissions from the plant to air pollutant concentrations would be small compared with modeled contributions of combined emissions from the plant and existing regional sources, even near the plant site, the modeled concentrations shown in Table 4.2.2 were dominated by other sources in the region (e.g., the Turris Mine for PM_{10}, and the Kincaid Generating Station in Kincaid and the A.E. Staley Manufacturing Company in Decatur for SO_2 and NO_2). Specifically, the prevalence of other regional sources is indicated by comparing the modeled concentrations and their locations in Table 4.2.1, which are based on emissions from only the boiler stack at the proposed facility, with those in Table 4.2.2, which are based on combined emissions from the proposed facility and from regional sources.

The modeled concentrations, when including regional sources, are much higher (by a factor of 3 or more) and the locations of the maximum concentrations are farther from the proposed facility and in different directions from those produced by modeling only emissions from the proposed facility.

The maximum modeled pollutant concentrations were added to monitored background concentrations (from Table 3.2.1) to obtain estimates of cumulative impacts for comparison with NAAQS (Table 4.2.2). This procedure is conservative because any effects of the regional modeled sources, which would also be included in the monitored background data, would be double-counted. The 24 hour averaged PM_{10} concentration estimated by this procedure was 94% of the NAAQS; concentrations of SO_2 and NO_2 were less than 50% of their respective NAAQS, and the annual concentration of PM_{10} was less than 75% of the NAAQS. As indicated from the PSD analysis, and as shown in Table 4.2.1, the highest modeled concentration increases of PM_{10} from the proposed power plant (i.e., 2 $\mu g/m^3$ for 24 hour PM_{10}) would be more than a factor of 10 below the modeled concentrations from other sources in the region. Thus, the proposed power plant would be an extremely small contributor to ambient air PM_{10} concentrations.

Table 4.2.2. National Ambient Air Quality Standards (NAAQS) impact analysis for combined effects of regional sources and the proposed power plant

Pollutant[a]	Averaging period	NAAQS[b]	Modeled concentration[c] and location	Modeled Impact	Ambient background concentration[d]	Total Impact	
		(μg/m³)	(μg/m³)	% NAAQS	(μg/m³)	(μg/m³)[e]	% NAAQS
SO_2	3-hour	1,300	267; 1.8 mi NNW	20	165	432	33
	24-hour	365	100; 4.4 mi NW	27	71	171	47
	Annual	80	17; 1.4 mi WNW	21	13	30	38
NO_2	Annual	100	5; 3.2 mi WNW	5	36	41	41
PM_{10}	24-hour	150	60; 4.0 mi SW	40	81	141	94
	Annual	50	11; 0.9 mi NNE	22	26	37	74

[a]The chemical symbols for the pollutants are as follows: SO_2 = sulfur dioxide; NO_2 = nitrogen dioxide; PM_{10} = particulate matter less than 10 μm in diameter.
[b]NAAQS are established under the Clean Air Act to protect public health and welfare with an adequate margin of safety.
[c]Maximum modeled concentration from existing regional sources plus the proposed power plant, except that the 24 hour PM_{10} concentration is the 3-year average of each year's third highest concentration, which corresponds with the standard.
[d]From Table 3.2.1.
[e]The sum of the modeled concentration and the ambient background concentration.

In addition, the conservative analysis procedure used to model particulate (and other criteria pollutant) concentrations results in air quality impact values that substantially over-estimate the values that would actually be expected from the proposed power plant. Thus, no exceedances of any NAAQS would be expected to be produced by the power plant at any location where a member of the general public would be likely to be exposed. Because the modeled concentrations are substantially below the NAAQS, emissions of SO_2, NO_2, and PM_{10} would not be expected to result in any adverse effects on human health and welfare.

4.2.2.2 Ozone Formation

Ozone (O_3) is a pollutant of concern because existing background levels in the ambient air are close to the NAAQS (Table 3.2.1). Ozone is a secondary pollutant formed from *photochemical* reactions involving emissions of NO_x and volatile organic compounds (VOCs). The reactions involved can take hours to complete; thus, O_3 can be formed far from the sources of the precursor pollutants that initiate its formation. Therefore, the contribution of any particular source to regional O_3 concentrations cannot be readily quantified.

Table 4.2.3 compares projected annual emissions of NO_x and VOCs from the proposed power plant with 1999 emissions from Sangamon and Logan counties. The proposed plant would increase annual NO_x emissions by an estimated 548 tons, or about 2% of the total emissions from existing sources in the two-county area. Estimated annual VOC emissions from the proposed plant would be 127 tons, or about 1% of existing emissions from sources in the two-county area. Because O_3 near Elkhart is likely to be influenced by pollutants emitted from a region larger than only those two counties, the above estimates of the percentage increases of NO_x and VOCs from the proposed power plant, which could affect O_3 near Elkhart, are likely to be upper-bound estimates.

The higher of the two percentage increases (2%) calculated for O_3 results from NO_x emissions. The 2% increase in annual NO_x emissions was calculated by integrating the maximum hourly NO_x emission level of 125 lb from the power plant over an entire year. Assuming NO_x emissions from other sources in the two-county area are produced continuously at a steady rate over a year, the maximum hourly emission level from the proposed power plant would represent a 2% increase. The impact on hourly O_3 formation from photochemical reactions involving NO_x would be expected to vary with the hourly NO_x levels.

Assuming, as a rough estimate, that the 2% increase in NO_x results in a 2% increase in O_3 concentration, the 1 hour ambient O_3 concentration of 196 $\mu g/m^3$ (Table 3.2.1) would be expected to increase to 200 $\mu g/m^3$, which is still well below the NAAQS of 235 $\mu g/m^3$. Although this 4 $\mu g/m^3$ increase in ambient O_3 concentration is based on an assumed linear relationship between NO_x emissions and O_3 level, the small contribution of NO_x emissions from the proposed power plant to ambient NO_x levels would be extremely unlikely to cause any exceedance of the 1 hour NAAQS for O_3. Sufficient data are not yet available to evaluate the effects of the proposed project in terms of the new 8 hour O_3 standard.

Table 4.2.3. Emissions of ozone precursors from the proposed power plant compared with emissions from Logan and Sangamon Counties in 1999

Pollutant	Proposed power plant (tons/year)	Sangamon County (tons/year)	Logan County (tons/year)	Total Two-County emissions (tons/year)	Power plant emissions (% of Two-County Total)
NO_x	548	21,879	4,976	26,855	2
VOCs	127	9,748	2,581	12,329	1

Source: Illinois emissions obtained from the U.S. Environmental Protection Agency (2002).

4.2.2.3 Acidic Deposition

Acidic deposition, which is more commonly known as *acid rain*, occurs when SO_2 and NO_x are chemically transformed and transported in the atmosphere and deposited on the earth's surface in the form of wet (rain, snow, fog) or dry (particle, gas) chemical agents. The SO_2 and NO_x are readily oxidized in the atmosphere to form sulfates and nitrates. Subsequently, the sulfates and nitrates may form sulfuric acid and nitric acid when combined with water, unless neutralized by other chemicals. Deposition of these acids over time may contribute to the acidification of lakes and subsequent damage to aquatic systems. Forests and agricultural areas are also potentially vulnerable because acidic deposition can cause leaching of nutrients from soils, inhibit microorganisms that convert atmospheric nitrogen into fertilizers for plants, and contribute to the release of toxic metals (EPA 1988). Acidic deposition also contributes to the corrosion of metals and deterioration of stone in buildings, statues, and other cultural resources. Sulfate particles and NO_x also reduce visibility by interfering with light transmission in the atmosphere.

SO_2 and NO_x can be transported by wind for hundreds of miles from one region to another before deposition onto earth in the form of acid rain. Therefore, the air mass moving over any given area will contain both residual emissions from sources in distant areas and emissions from sources in areas over which the air mass has more recently passed. This continuing depletion and replenishment of emissions along the flow path of an air mass results in uncertain relationships between specific sources of emissions and acid deposition at any particular location.

Projected annual increases in SO_2 and NO_x emissions from the proposed power plant are estimated to be 1,042 tons and 548 tons, respectively (Table 4.2.4). Whether a ton of SO_2 or a ton of NO_x is more damaging depends on several factors, including the nature of the resource being impacted and the time scale under consideration. In general, however, no clear basis exists to consider either SO_2 or NO_x as a more damaging precursor of acidic deposition than the other on a ton-for-ton basis.

Table 4.2.4 compares projected annual emissions of SO_2 and NO_x from the proposed power plant with 1999 emissions from the State of Illinois (EPA 2002), which was chosen as an appropriate area to represent emissions affecting acidic deposition. Table 4.2.4 shows that estimated emissions of SO_2 and NO_x from the proposed power plant represent one-tenth of one percent or less of existing emissions from the State of Illinois. Thus, the expected contribution of emissions from the proposed power plant to acidic deposition would be negligible.

Table 4.2.4. Emissions of acid-rain precursors from the proposed power plant compared with emissions from the State of Illinois in 1999

Pollutant	Proposed power plant (tons/year)	Illinois (tons/year)	Power plant emissions (% of Illinois emissions)
SO_2	1,042	1,055,000	0.10
NO_x	548	1,112,000	0.05

Source: Illinois emissions obtained from the U.S. Environmental Protection Agency (2002).

In addition, Elkhart Hill, which is located approximately 1 mile northwest of the proposed power plant site and which has a maximum elevation of about 200 ft above the plant site, would be considered to be in the near field relative to emissions from the power plant. The atmospheric reactions necessary to create sulfuric acid and nitric acid take time and are not near-field phenomena. Because the proposed plant would be relatively close to Elkhart Hill, emissions of SO_2 and NO_x from the plant would not be expected to undergo the level of atmospheric transformation and deposition required for their confining air mass to affect Elkhart Hill.

4.2.2.4 Global Climatic Change

The combustion of fossil fuels has contributed to an increased atmospheric concentration of CO_2 over the last century. Because CO_2 contributes to the earth's greenhouse effect, the increased CO_2 concentration may have contributed to a corresponding increase in globally averaged temperature in the lower atmosphere (IPCC 1992). However, because CO_2 is stable in the atmosphere and essentially uniformly mixed throughout the troposphere and stratosphere, the climatic impact does not depend on the geographic locations of sources. Therefore, CO_2 emissions from a specific combustion source only effective in altering atmospheric CO_2 concentrations to the extent that they proportionally contribute to the total quantity of fossil fuel combustion emissions that increase global CO_2 concentrations. A corresponding increase in atmospheric sulfate loading from fossil-fuel combustion may also act to reduce global-scale warming by increasing the reflection of incoming solar radiation (Mitchell et al. 1995).

The proposed power plant would increase global CO_2 emissions by about 911,000 tons per year, which represents about 0.003% of the current annual global CO_2 emissions from fossil fuel combustion (Table 4.2.5). The proposed plant would also increase SO_2 emissions by an estimated 1,042 tons per year. Assuming SO_2 emissions are proportional to atmospheric sulfate loadings, and global anthropogenic SO_2 emissions are about 145 million tons per year (Hameed and Dignon 1992, Graedel and Crutzen 1993), the proposed plant would increase global anthropogenic sulfate loadings by about 0.0007%. The added atmospheric sulfate would act to decrease the amount of solar radiation available for heating the lower atmosphere and thus tend to offset CO_2-induced warming, although a quantified and accurate estimate of the amount of offset cannot be provided based on the current state of knowledge. In any case, although the CO_2 emission rate from the proposed power plant would be large, relative to the global environment the expected contribution of emissions from the proposed power plant to global climate change would be negligible.

Table 4.2.5. Comparison of CO_2 emissions from the proposed power plant with U.S. and global CO_2 emissions from fossil fuel combustion

Power plant (tons/year)	U.S. (tons/year)	CO_2 emissions (% of U.S. emissions)	Global (tons/year)	CO_2 emissions (% of global emissions)
911,000	6,007,667,000	0.015	26,100,000,000	0.003

Source: U.S. and global CO_2 emissions obtained from Marland et al. (2002) and converted to tons of CO_2 per year. Emissions from combustion of coal, oil, and natural gas and from gas flaring are included.

4.2.2.5 Conformity Review

Section 176(c) of the Clean Air Act requires that Federal actions conform to State Implementation Plans (SIPs) developed for attainment of National Ambient Air Quality Standards, and a rule ("Determining Conformity of General Federal Actions to State or Federal Implementation Plans") for implementing the requirement was promulgated by EPA on November 30, 1993 (58 *FR* 63214). The rule establishes the criteria and procedures necessary to ensure that Federal actions conform to the applicable SIP and comply with provisions of the Clean Air Act. The rule requires that all emissions of criteria air pollutants and volatile organic compounds (1) are identified and accounted for in the SIP and (2) conform to a SIP's purposes of eliminating or reducing the severity and number of violations of the National Ambient Air Quality Standards and of achieving expeditious attainment of such standards. Actions in a non-attainment area or a maintenance area are affected by the provisions of the conformity rule. The proposed plant would be located within an attainment area; thus, the provisions of the conformity rule would not apply and a conformity determination would not be required.

4.2.2.6 Hazardous Air Pollutants

Federal Regulations

On December 20, 2000, the U.S. Environmental Protection Agency (EPA) published a notice in the *Federal Register* announcing EPA's Regulatory Finding on the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units (65 *FR* 79825). EPA's finding was that regulation of hazardous air pollutant emissions from coal- and oil-fired electric utility steam generating units under Section 112 of the Clean Air Act was appropriate and necessary. EPA also reiterated an announcement from a 1998 Report to Congress that, for the utility industry, mercury from coal-fired electric utility steam generating units was the hazardous air pollutant of greatest concern for public health. Electric utility steam generating units produce the largest quantity of human-caused mercury emissions in the United States, releasing about 48 tons (or about 40% of the total U.S. emissions) of mercury into the air each year.

EPA's determination in December 2000 required a proposed regulation by December 2003 and a final rule by December 2004. Currently, EPA is considering a regulatory approach that would cap mercury emissions from coal-fired power plants at 34 tons-per-year by 2010. The cap would be further reduced to 15 tons-per-year by 2018. Emissions sources would be assigned an allowance to emit mercury, and utilities would be permitted to purchase or sell allowances and adjust their emissions accordingly. EPA may also consider an alternative approach for controlling mercury emissions based on application of the Maximum Achievable Control Technology (MACT) rule of Section 112 of the Clean Air Act. Under the MACT rule, regulations would be based on mercury emissions as measured at the best performing plants, and installation of control technology that could achieve those low emission levels at each specific plant would be required by the end of 2007.

Combustion Emissions of Hazardous and Other Air Pollutants

Many chemical species can be emitted in trace quantities during the combustion of coal. These species would include materials from the list of 188 hazardous air pollutants identified under Title III of the 1990 Clean Air Act Amendments. The characteristics and amounts of emissions would depend on combustion temperature, fuel feed mechanism, the composition of the fuel, and the performance characteristics of systems used for controlling emissions. Temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the partitioning of emissions into bottom ash and fly ash. Trace metal emissions also depend on the concentration of the metal in the fuel, the combustion conditions, the type of particulate control device used, and the physical and chemical properties of the metal.

As indicated in Section 2.1.7.1, the proposed plant would emit a small amount of volatile organic compounds and trace quantities of other (non-criteria) pollutants, such as mercury, beryllium, arsenic, various heavy metals, and hydrochloric acid (hydrogen chloride). The following discussion provides an overview of the formation and significance of such species during coal combustion processes.

Organic compound species produced during combustion include volatile organic compounds that remain in a gaseous state in ambient air, semi-volatile organic compounds, and condensable organic compounds. Volatile organic compounds are defined as any organic compounds that participate in atmospheric photochemical reactions. Hydrocarbon emissions from combustion sources are primarily aliphatic, oxygenated, and low molecular weight aromatic compounds that exist in the vapor phase at flue gas temperatures. Included are emissions of alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes. Organic compounds emitted in a condensed phase typically consist of polycyclic organic matter (POM) and polynuclear aromatic hydrocarbons (PAH). Polycyclic organic matter can be especially prevalent in the emissions from coal burning, because a large fraction of the volatile matter in coal exists as POM.

Pursuant to directions issued to EPA by Congress in Section 112 of the Clean Air Act, EPA prepared a Report to Congress covering an extensive Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units (EPA 1998). The study included initial collection of HAP emissions test data from 52 utility units, including a range of coal, oil, and gas fired units, and the test data were used to estimate HAP emissions from all 684 utility plants in the United States. Although not specific to the proposed plant, the EPA information provides an indicator of the potential impacts to be expected from the proposed plant. Of the 188 HAPs listed in Section 112 of the Clean Air Act, a total of 67 HAPs were identified in the emissions testing program as potentially being emitted by utilities. Twelve pollutants (arsenic, beryllium, cadmium, chromium, manganese, nickel, hydrogen chloride (HCl), hydrogen fluoride (HF), acrolein, dioxins, formaldehyde, and radionuclides) were identified as priority pollutants for further study based on potential for inhalation exposures and risks. Two additional pollutants (mercury and lead), in addition to arsenic, cadmium, dioxins, and radionuclides, were identified as priority for multi-pathway exposure.

EPA reports that, although polychlorinated biphenyl (PCB) formation is thermodynamically possible from combustion of fuels containing some chlorine, formation of PCBs during combustion is unlikely due to short combustion residence times at conditions favoring PCBs and to low chlorine concentrations. Dioxins (heterocyclic, chlorinated hydrocarbons) and furans (heterocyclic C_4H_4O compounds) can form from high-temperature combustion of fuels containing organic, chloride, and fluoride compounds. However, with efficient mixing, oxygen availability, and adequate residence time at typical combustion temperature (e.g., 800 – 1,000°C), which would be representative of the LEBS plant, PCBs, polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF) may be efficiently destroyed. EPA reported from their studies of emissions from utilities that dioxins were not detected in over 40% of their measurements, and EPA's estimate was that coal-fired utilities emit 0.2 lb/year of dioxin. Chlorinated polynuclear aromatic compounds (PNAs) can be formed by catalyzed reactions on fly ash particles at low temperatures in equipment downstream from the combustion chamber.

Formaldehyde (H_2CO) can be formed and emitted during the combustion of coal and would be present in the resulting flue gases in the vapor phase. Because formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion, large units with efficient combustion, closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long retention times should have lower formaldehyde emissions rates than do small, less efficient combustion units.

Mercury emissions from coal combustion, which are the primary focus for regulation by EPA as a hazardous air pollutant, may exist in three different forms – elemental mercury, divalent oxidized mercury, and mercury adsorbed onto fly ash or other particles. Information collected by EPA from emission tests on 84 generating plants representing different plant configurations and coal ranks indicated that mercury speciation at the furnace exit was principally influenced by chlorine content of coal and temperature, with about 75-90% of the mercury reported to be adsorbed on particles or existing as divalent oxidized mercury for coals with chloride contents greater than 150-200 ppm.

Hazardous Air Pollutant Emissions Estimates

Emission factors are commonly used to establish emission inventories in the absence of directly measured emissions. Emission factors have been compiled by EPA (EPA 42) for hazardous materials from combustion operations representing those proposed for the LEBS plant – that is, for combustion of bituminous coal in a pulverized coal-fired system that uses a wet bottom boiler and that is equipped with emissions control devices consisting of an electrostatic precipitator and a wet scrubber. The proposed plant would combust Illinois bituminous coal in a slagging combustor and would use both an electrostatic precipitator and a wet limestone scrubber for emissions control.

Table 4.2.6 presents EPA's reported emission factors of various HAPs in lb/MM Btu from combustion of bituminous coal. In addition, trace metal characterization information developed by the Illinois State Geological Survey (ISGS) for coals mined in Illinois (ISGS 2003) were reviewed, and results are provided in the table for comparison with the emission factor information reported by EPA. For arsenic, beryllium, chromium, manganese, nickel, and hydrogen fluoride, the concentrations based on analysis of Illinois coal are comparable to the uncontrolled emission factor values reported by EPA. For both mercury and cadmium, the concentrations based on analysis of Illinois coal are about 50% lower than the values reported by EPA for uncontrolled emissions, while the coal analyses for lead and fluoride are 3 to 4 times higher than the uncontrolled emission factor values reported by EPA.

Based on the coal feed rate of 47 tons-per-hour for the proposed plant and the coal heating value of 10,450 Btu/lb, the table also presents both the rate of trace material feed to the plant in lb/hour using the ISGS analyses for Illinois coals and the rate of uncontrolled emissions from the plant in lb/hour based on the EPA emissions factors. EPA has also compiled information on the average trace material (i.e., arsenic, beryllium, cadmium, chromium, manganese, nickel, selenium, and POM) removal efficiencies using various control devices, including electrostatic precipitators and wet scrubbers, which would both be used in the proposed plant. For these trace materials, the table also presents the estimated rates of hazardous air pollutant emissions that would be anticipated following the flue gas cleanup control devices.

Table 4.2.6. Estimated combustion HAP emission rates for selected trace materials

MATERIAL	EPA EMISSION FACTOR[(1)]	ILLINOIS COAL		UNCONTROLLED EMISSION RATE BASED ON EMISSION FACTORS	CONTROLLED EMISSION RATE
		CONTENT	FEED RATE		
	(lb/MM Btu)	(lb/MM Btu)	(lb/hour)	(lb/hour)	(lb/hour)
Arsenic	0.000538	0.00059	0.58	0.528	0.0058[(3)]
Beryllium	0.000081	0.00009	0.093	0.08	0.0046[(4)]
Cadmium	0.00007	0.000039	0.039	0.069	0.0039[(5)]
Chromium	0.00157	0.001	1.086	1.54	0.109[(6)]
HCl	0.057	0.13[(9)]	129.6[(9)]	56.0	
HF	0.007	0.0073[(10)]	7.2[(10)]	6.88	
Lead	0.000507	0.0019	1.86	0.5	
Manganese	0.00298	0.003	2.95	2.9	0.067[(7)]
Mercury	0.000016	0.0000071	0.007	0.016	
Nickel	0.00129	0.001	1.08	1.27	0.036[(8)]
POM	0.00000889[(2)]				0.009[(2)]
Selenium	0.00002434[(2)]	0.00015	0.147		0.024[(2)]

(1) Uncontrolled value, unless otherwise indicated.
(2) Controlled value reported by EPA, based on electrostatic precipitator.
(3) Based on EPA-reported control efficiency of 98.9% using an electrostatic precipitator and scrubber.
(4) Based on EPA-reported control efficiency of 94.3% using a FGD scrubber.
(5) Based on EPA-reported control efficiency of 94.4% using a FGD scrubber.
(6) Based on EPA-reported control efficiency of 92.9% using an electrostatic precipitator and scrubber.
(7) Based on EPA-reported control efficiency of 97.7% using an electrostatic precipitator and scrubber.
(8) Based on EPA-reported control efficiency of 97.2% using an electrostatic precipitator and scrubber.
(9) Chloride content.
(10) Fluoride content.

Based on the uncontrolled emissions rates, under existing regulations the proposed plant would be considered a major source of hazardous air pollutants. Thus, the proposed plant would be subjected to review under Section 112(g) of the Clean Air Act.

Hazardous Air Pollutant Emissions Control

Particulate control technologies provide the capability to reduce hazardous air pollutants, particularly metals that would be vaporized in the combustion process but condensed onto solid flyash particles in the exhaust gas. The efficiency for removal of solid particles may not, however, correspond to the removal efficiencies for specific hazardous air pollutants or metals, due to the possibilities for enrichment of the metals on fine-sized particles. This phenomenon may be important for metals that volatilize at peak combustion temperature and condense as (or on) particulate at flue gas temperatures.

Mercury capture in control technologies depends on the relative amounts of the different possible mercury species present in flue gas. Mercury bound to particles can easily be removed in conventional particulate emission control devices such as electrostatic precipitators, which are generally effective in removing greater than 90% of all trace metallic hazardous air pollutants except for gas-phase pollutants, which include trace organic compounds, hydrogen chloride, and hydrogen fluoride. Divalent oxidized mercury is generally soluble in water and can be captured in wet scrubbers. Wet flue gas desulfurization systems are capable of capturing nearly all hazardous air pollutants other than elemental mercury and can generally capture more than 90% of divalent and particle-bound mercury. Elemental mercury is not soluble in water, does not react with reagents used in flue gas desulfurization systems, and is not captured in wet scrubbers. However, bituminous coals contain higher concentrations of chlorine and other constituents that promote oxidation and capture of mercury in conventional air pollution control devices. From Table 2.1.2, the chlorine content of Turris Mine coal is about 1,000 ppm; based on EPA's reported emission testing data, this chlorine concentration would promote divalent or particle-bound forms of mercury, which would be amenable to 75-90% removal in the electrostatic precipitator or wet scrubber planned for the proposed plant. At these levels of mercury control, EPA's emission factor for mercury would be reduced to 0.00004 lb/MM Btu to 0.0000016 lb/MM Btu, and the calculated rate of emissions from the plant would be 0.004 lb/hr to 0.0016 lb/hr (14 to 35 lb/year).

Based on reviews performed by the Illinois EPA, the Low Emissions Boiler System plant as proposed with both an electrostatic precipitator and a wet scrubber was determined to use Maximum Achievable Control Technology (MACT) technologies for emissions of hazardous air pollutants, as required by Section 112(g) of the Clean Air Act. The Illinois EPA also determined that the proposed plant would comply with Section 112(g) of the Clean Air Act and applicable National Emission Standards for Hazardous Air Pollutants (NESHAP; 40 CFR 63, Subpart B).

Permit compliance

The permit issued by the Illinois EPA for the proposed plant (Appendix D) requires emissions testing subsequent to startup of the plant. Testing is required for mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, hydrogen chloride, hydrogen fluoride, and dioxin and furan. Mercury identified in emissions from the plant must be characterized to determine the form of mercury in the emissions (i.e., bound to solid particles, as oxidized mercury, or as elemental mercury). Dioxin and furan measurements are required for a 3-year period.

For controlling mercury emissions, the Illinois EPA established a requirement for the proposed plant to achieve one of the following standards:

- An emission rate of 0.000004 lb/MM Btu, or emissions below the detection limit of established measurement technology, as demonstrated by periodic testing;

- A removal efficiency of 90% without injection of agents specifically used to control mercury emissions, as demonstrated by periodic testing;
- Injection of agents specifically used to control mercury emissions in a manner to achieve maximum practicable degree of removal, as demonstrated by proper equipment operation;
- Mercury control levels established by a revised PSD permit pursuant to Section 112(g) of the Clean Air Act, if required due to engineering limitations in meeting the above standards, as demonstrated by proper equipment operation; or
- The mercury emission control requirement established by the U.S. EPA pursuant to Section 112(d) of the Clean Air Act, upon adoption of a final mercury rule.

The Illinois EPA also established a mercury emission limit of 0.02 tons (40 lb) per year, or an hourly equivalent of 0.0046 lb based on plant operation at full capacity and 100% availability. Coal supplies to the proposed plant must also be analyzed for mercury and other metals and chlorine content.

Health and Ecological Effects

EPA developed inhalation exposure and cancer risk information from dispersion modeling of HAPs emissions from all 684 power plants included in the EPA study. For all but two of the 426 coal-fired plants that were studied, the lifetime cancer risks to the local (within about 30 miles) population due to inhalation exposure to HAPs emissions were less than one in a million. For the two plants with greatest risk, the local increase in lifetime cancer risk was a maximum of two in a million. EPA also analyzed noncancer risks due to inhalation of HAPs emissions. The highest estimated long-term HAP concentrations in the ambient air were found to be 10 to 10,000 times below the daily inhalation reference concentrations for exposures deemed likely to result in appreciable risk of deleterious effect during a lifetime, including lifetimes of sensitive groups.

Mercury is a highly toxic and persistent species that can bioaccumulate in the food chain. Atmospheric emissions of mercury eventually deposit onto land or water bodies, and deposition can occur near the emission source or at distant locations. Air transport and deposition patterns of mercury depend on factors that include the form in which mercury is released (e.g., elemental mercury typically deposits farther from the source), the stack height, temperature of the exhaust gas, meteorological conditions, and chemical transformations during atmospheric transport. Deposits of mercury can be transformed into methyl mercury, which is a more toxic form of mercury that accumulates in aquatic species (e.g., fish). Human and wildlife are mainly exposed to mercury by consumption of fish and other kinds of seafood containing elevated levels of mercury. Neurotoxicity is the predominant concern from exposure to methyl mercury, which has a half-life in the human body of about 75 days. Ingested methyl mercury is almost completely absorbed into the blood and distributed to all tissues, including the brain and through the placenta of pregnant women to the fetus and fetal brain. Because a developing fetus is most sensitive to the effects of methyl mercury, the greatest health concern for humans is the consumption of mercury-contaminated fish by women of childbearing age. Offspring born of women exposed to high levels of methyl mercury during pregnancy exhibit a variety of developmental neurological abnormalities, including delayed development, cerebral palsy, and reduced scores on neurological tests.

EPA evaluated exposures, hazards, and risks due to hazardous air pollutant emissions from coal-fired electric utility steam generating units, considering both inhalation and ingestion exposure pathways, for six hazardous air pollutants: mercury, radionuclides, arsenic, cadmium, lead, and dioxins. EPA concluded that for arsenic and cadmium (and other metals, including nickel and chromium) a potential concern exists for carcinogenic effects, although the cancer risks are not high. Inhalation exposure to inorganic arsenic is associated with lung cancer, and ingestion produces increased risks of skin, bladder, lung, and liver cancers. Ingestion of large amounts of chromium can cause stomach ulcers and kidney and liver damage, and inhalation can produce lung irritation, bronchitis, pneumonia, asthma, or other respiratory illnesses. The chances of developing cancer as a result of a person's life-long exposure to chromium emissions from a coal-fired power plant were estimated by EPA as one (or less) in a million. Exposures to small quantities of nickel over long time periods can result in allergic reactions, particularly itching of the skin. Ingestion of nickel can produce vomiting and diarrhea, and inhalation can produce asthma. EPA has determined that the cancer risk from nickel emissions from coal-fired plants would be less than one chance in a million for a person with life-long exposure to coal-fired power plant emissions.

Dioxins (along with hydrogen chloride and hydrogen fluoride) were identified as hazardous air pollutants of potential concern. Hydrogen chloride and hydrogen fluoride vapors can irritate the lungs and cause bronchitis and may cause skin rash, irritation, and eye damage. Neither hydrogen chloride nor hydrogen fluoride has been found to cause cancer. EPA evaluated exposures to hydrogen chloride at power plants and determined that emissions do not pose a significant health risk. The amount of hydrogen fluoride released to the atmosphere from power plants was determined by EPA to never reach unhealthy levels. Information on the human health effects of dioxins was limited but suggested an increased risk for cancer from dioxin exposure. Dioxin exposures may also result in skin rashes, vomiting, fever, and abdominal pain.

EPA found that the remaining hazardous air pollutants (i.e., radionuclides and lead) from coal-fired plants did not appear to be concerns for public health. EPA determined that exposures to radionuclides from utilities were substantially lower than the risks due to natural background radiation. Ingestion of large quantities of manganese can harm the human brain, and inhalation of large quantities of manganese dust can irritate the lungs, cause impotence, and cause mental confusion and clumsy body movement. Manganese has not been found to cause cancer in humans, and evaluations by EPA indicate that manganese exposures for humans living near power plants would never exceed 5% of the safe exposure level for inhalation.

For the proposed project, trace emissions of hazardous air pollutants and other non-criteria pollutants would not be expected to result in adverse impacts on the health of workers, members of the public, or ecological resources.

4.3 WATER RESOURCES

4.3.1 Construction

During the construction period, the contractor(s) selected for erecting the proposed power plant would be responsible for providing potable water from off-site sources until the proposed new wells (Section 2.1.6.2) and water treating equipment have been installed, tested, and certified to supply an acceptable source of water. The construction contractor(s) would supply temporary equipment for fire protection of the construction site until more permanent sources of fire protection water from the Turris Mine or the new water wells would be available. The field drainage runoff and well water systems would be used to provide water for construction activities that would not require potable water. The Fresh Water Pond at the Turris Mine would also be available for providing non-potable water.

Water uses during construction would include rinsing of equipment and structures, preparation of mixtures such as concrete, and dust suppression. Water for dust suppression would be applied to site roads and construction areas only when required by site conditions. Water usage for such purposes during dry periods would be expected to total 8,000 gpd and would be obtained from groundwater wells. During power plant construction, the installed new piping would be flushed with a good quality, de-ionized water; the volume of water used would amount to several times the volume of the piping systems. The new boiler would also be filled and flushed with water several times. The boiler would subsequently be pressure tested at progressively higher pressures, until achieving successful check-out at 150% of the rated operating pressure of the boiler. Neither retention pond water nor well water would be expected to be available for use in preparing concrete, etc., during the early part of the construction effort. Water from the Turris Mine's process water system would be available to extinguish any accidental fires and to provide water for dust suppression during construction.

During plant construction, portable sanitary facilities would be provided to minimize requirements for additional sanitary water. The existing and proposed new sanitary facilities would only be used by authorized, existing employees. Construction contractor(s) would need to provide temporary facilities for construction workers. The relatively short duration and size of the project as well as the intermittent use and consumption of water during construction would not cause the existing water sources to be overdrawn.

All construction would be performed in accordance with an erosion and sedimentation control plan. Standard engineering practices, such as use of straw berms, installation of liners, application of cover materials, and grading, would be implemented as required to minimize runoff, erosion, and sedimentation near the site. Impacts attributable to construction-related runoff, erosion, and sedimentation would be minimal.

Accidental spills of construction materials, such as solvents, paint, caulk, oil, and grease, that could contain hazardous substances would be cleaned in a timely manner and in accordance with a spill prevention, control, and countermeasures plan. Runoff of accidental spills into the Lake Fork Creek watershed would be minimized. A stormwater pollution prevention plan and an installation spill plan would be developed for the proposed plant. These plans would provide specific measures for spill prevention, such as secondary containment for tanks.

4.3.2 Operation

During normal operations, the only water to be discharged directly from the proposed power plant would be an additional 3 gpm (conservative value) through the existing sewage treatment facility operated at the Turris Mine and 62 gpm of cooling tower blowdown to the Turris Mine's fresh water pond, which is used to provide water for coal washing.

The new sanitary discharge of 3 gpm would be piped to the existing treatment facility at the Turris Mine and combined with sanitary waste produced at the mining and coal processing complex. The added waste would have minimal effect on the existing treatment system, which was designed to handle 200 employees, but which is operating in support of a considerably smaller staff. The 3 gpm estimate for added sanitary discharge is a conservative value. The proposed plant would be expected to host a maximum of 30 employees and visitors per day. Based on a person's normal usage of about 50 gallons of water per day for drinking and sanitary purposes, only about 1,500 gallons per day (approximately 1 gpm) of water may be required.

Approximately 98 gpm of water would be associated with slag waste, water conditioning sludge, and FGD gypsum waste. While these materials could potentially be marketed, off-site disposal may be required. All other water used in the power plant (1,032 gpm), in addition to water for sewage treatment water, cooling tower blowdown, and waste handling, would be released through either evaporation or cooling tower drift.

The total water demand for the plant (1,195 gpm, or 1.7MM gpd) would be serviced by the development of a field tile drainage system and retention pond, with additional water supplies available from groundwater wells. Water demand for the plant would primarily be provided from the field drainage system during normal operations. During off-normal conditions, such as dry periods, drought, or extreme cold, when the field drainage system and retention pond would not be capable of meeting the water demand for the plant, groundwater from the well field that would be developed as part of the proposed project would supply the additional water required for operations.

The maximum measured flow in the field tile drainage system, which fluctuates seasonally, is 2 MM gpd. The water holding capacity of the retention pond (approximately 107.5 MM gallons) would support about 60 days of power plant operation without additional inflow. A groundwater study (Farnsworth Group 2001) within the plant area indicated that a 2 MM gpd sustainable water supply could be obtained using a multiple well system of properly spaced and managed wells. Groundwater could, therefore, provide a supplemental source of water for the proposed power plant during times of low surface water availability from the field tile drainage system and the retention pond.

The primary water source for the groundwater wells would be water stored within aquifers. The locations for up to 6 new groundwater supply wells would be based on data developed from an extensive groundwater survey conducted to identify sources of water that would minimize effects on adjacent wells and on nearby wells that serve the Turris Mine and the village of Elkhart. Figure 3.4.5

identifies the locations of 11 groundwater supply test wells included in the survey. The groundwater survey data indicated that aquifers have substantial capacity and would be capable of providing the proposed power plant with water sufficient to endure up to 3 months of drought. In the event of an extreme drought, the proposed plant may need to reduce operations to preserve the municipal water supply.

The initially estimated water requirement for the power plant was 1,400 gpm (about 2 MM gpd). To achieve this water flow, a new well field that included a well in relatively close proximity to the village of Elkhart's well was considered to be necessary. However, based on current power plant design considerations, a reduced water requirement (1,195 gpm) would be needed, and expectations are that the reduced water requirement could be satisfied from other wells within the new well field. On this basis, development of a well in close proximity to the Elkhart municipal well may not be required. Current plans would result in development of this well only if absolutely necessary to meet water requirements.

Of the wells studied as candidates for development to support the power plant's water requirements, well (TH1-01) was closest (within 1,300 ft) to the village of Elkhart's municipal well. Pumping tests performed on well TH1-01 by the Farnsworth Group (2001), which resulted in an estimated sustained yield of 250 gpm, indicated a drawdown estimated at 70.6 ft from a total available drawdown of 79.6 ft. The estimated transmissivity for the aquifer in the vicinity of well TH1-01 was approximately 2,500 gpd/ft. Potential interference between well TH1-01 and the Elkhart municipal well, if well TH1-01 should be used, could result in excessive drawdown at the municipal well. If well TH1-01 is used and results in an excessive drawdown at the municipal well, increased operating expenses for the village well could result, and the yield from the village well could be reduced. The possibility of interference was investigated using the results from a pumping test by Kohlhase and Lott (2001). Considering steady-state operation of well TH1-01 under *leaky artesian conditions*, Kohlhase and Lott analyzed the data for well TH1-01 and the village of Elkhart's municipal well and determined that the potential interference between the two wells would result in a long-term impact of 6 ft of additional drawdown at the Elkhart municipal well, which would not be significant to operation of the municipal well. The estimated interference of 6 ft is supported by the results from the pumping test of well TH1-01, which was conducted over a period of 72 hours at a pumping rate of 230 gpm. During the test, the water level at Elkhart's municipal well was measured, and the maximum drawdown was 4 ft.

The other wells considered for development as part of the project would be east of the power plant site, approximately 12,000 ft from Elkhart's municipal well. Pumping tests on two of these wells (TH5-01 and TH9-01) resulted in estimated sustained yields of 470 gpm and 525 gpm, respectively. In analyzing results from the pumping tests, potential interference between wells TH5-01 and TH9-01 and an additional well at an equal distance from TH9-01 was considered. Potential interference was estimated to be 7.0 ft for a pumping rate of 400 gpm. This level of interference could have an impact on the yield of TH9-01, depending on the effects of the subsurface boundaries associated with the aquifer. Interference between the east wells and TH1-01 was not considered quantitatively. The boring logs associated with the drilling of wells TH1-01, TH5-01, and TH9-01 do not suggest any connections between the subsurface formations supporting the east wells and TH1-01. Available data are not sufficiently complete, however, to demonstrate that no connection would exist.

To conservatively assess interactions between the east wells and TH1-01, Kohlhase (2001) assumed a perfect connection existed. Using the hydraulic properties determined from the pumping tests and a total pumping rate of 1,325 gpm, which is projected to be the yield from 3 wells in the eastern well field, the calculated potential interference at TH1-01 ranged from 2.5 to 0.1 ft, depending on the choice for the specific yield. This level of interference should be considered a worst case bounding estimate of the potential interference from the operation of all wells at full capacity, with the maximum possible degree of connectivity between the wells.

During normal operating conditions, the wells to be developed as part of the project would be expected to easily provide the 50 gpm (Figure 2.1.6) required for domestic use and boiler feed from the combined sustainable yield estimate of 995 gpm for wells TH5-01 and TH9-01. During periods of extreme drought, the sustained yield from those two wells, as determined from the pumping tests, would be capable of providing about 83% of the total water demand of 1,195 gpm for the proposed plant. Additional wells (up to a total of 6 based on existing groundwater yield information) would be installed to ensure adequate flow rate for the plant and to provide a margin of safety in the event that any of the identified wells should be out-of-service for maintenance. Consequently, the available water resources would be sufficient for the proposed plant, and the municipal well for the village of Elkhart would not be adversely affected from operation of the proposed power plant. Also, because no direct connection between Lake Fork Creek and the groundwater aquifer has been determined to exist, no impact to surface flows would result from use of groundwater to supply all water requirements for the power plant during periods of extreme drought.

Some uncertainty exists in the potential yield of the new groundwater wells and the field drainage system, and this uncertainty becomes more significant when considering the potential consequences of extended drought conditions. In addition, pumping groundwater from the aquifers could induce additional infiltration to occur if the cone of depression developed by the wells or well field intersected the streambed of Lake Fork Creek. To ensure that the water supply for the proposed plant would be adequate and that the municipal water supply for the village of Elkhart would not be adversely affected by power plant operations, monitoring of each well developed for the project would be performed by Corn Belt Energy. The drawdown resulting from well pumping and the associated water quality in the aquifer would be monitored. Criteria would be developed for long-term use and management of the well field that would be installed. Operating procedures, data collection and monitoring, and guidelines for optimizing performance of the new well field would be established, to ensure that the well field would remain a reliable and acceptable source of water, if needed for the proposed plant.

While an existing monitoring well (M8) east of the slurry impoundment at the mine exhibits elevated levels of dissolved solids and other contaminants (Section 3.4.3), adjacent wells do not exhibit similar contamination. The new water supply wells to be installed approximately 2 miles from Well M8 would not be expected to impact the plume of contaminated water in well M8.

Groundwater and surface water use in the State of Illinois is currently regulated under the principal of reasonable use (Beck et al. 1996). Permits are not required for groundwater withdrawals. Similarly, permits are not required for surface water withdrawals, but restrictions may be imposed during periods of low-flows. Any restrictions of this type would not be expected to affect the proposed power plant.

Accidental spills during operation of the proposed power plant would be cleaned in a timely manner and in accordance with a spill prevention, control, and countermeasures plan. Runoff into the Lake Fork Creek watershed and seepage into the ground would be minimal. Surface water runoff that would be collected in the retention pond would not measurably affect Lake Fork Creek.

Tank and vessel storage areas would be enclosed within berms or dikes that would be designed to provide sufficient holding capacity to contain accidental leaks and spills. Most tanks and storage vessels would be expected to be constructed above ground with adequate spill protection. Only an oil-water separator and a wastewater collection basin would be considered for underground installation. All tanks and vessels would be designed to meet applicable codes and standards. Since coal for the power plant would be provided from the Turris Mine's clean coal silo, no effects on surface water or groundwater from leaching of coal storage piles would result. No new coal storage would be required. Waste product from combustion operations at the power plant would be a vitrified (glass-like) material that is essentially inert. Thus, no contaminated leachate from the coal combustion ash would be generated.

4.4 GEOLOGY

4.4.1 Geology and Seismicity

Buildings and process structures required for the proposed power plant would be designed to withstand a PGA of 0.075 g, which is higher than PGAs that would be expected to occur from seismic activity at the site during the lifetime of the plant. No damage to facilities within the power plant would be expected to result from earthquakes.

Equipment and facilities for the proposed power plant would be installed at a surface location that would minimize the risk of subsidence impact from underground coal mining. The coal resources directly beneath the proposed site, which are owned by Turris Coal Company, have not been mined. The proposed plant would be located beyond the edge of mine workings above a solid block of coal having a minimum width of 600 ft between the closest, neighboring mined coal panels (Figure 3.4.2). The plant area, at the subsurface level of the coal resources, would be bordered by residual barrier pillars of coal separating the plant area from formerly mined areas rather than active mining areas.

The coal removed from the mine at Elkhart is overlain by over 200 ft of unconsolidated overburden, consisting of weak clays, sandy or silty clays, and sand and gravel. Based on an assessment of current geological conditions at the project site (Chugh 2001), subsidence of the land proposed for the power plant would not be anticipated. The slow deformation rates anticipated in the mine floor should dissipate within the unconsolidated overburden, which would avoid major fracturing and temper potential adverse effects by healing small fractures.

Measurements of surface subsidence above room-and-pillar mine workings similar to those beneath the site proposed for the power plant have resulted in *angle of draw* values of 29° for an assumed vertical subsidence of 0.003 ft. The value of 0.003 ft was assumed as the point of *zero deformation* for protection of sensitive LEBS plant equipment, since the equipment would require subsidence protection for a plant lifetime of 35 years and the plant's steam turbine would require stability for efficient operation. The surface distance from a point vertically above the edge of the mine workings to the point of zero deformation is termed the *influence zone*, which represents the extent of potential surface subsidence impact from the mine edge. Figure 4.4.1 depicts these concepts. Assuming a slightly more protective angle of draw of 30°, the influence zone from underground mining on potential surface movement at the proposed LEBS site is shown in Figure 4.4.2.

The impacts from surface deformation due to mined-out areas of the Turris Mine would not be expected to adversely impact the proposed power plant. However, for added protection, plant equipment, particularly the turbine, would be expected to be more centrally located, equidistant from the edges of the nearest zones of influence, as shown on Figure 4.4.2.

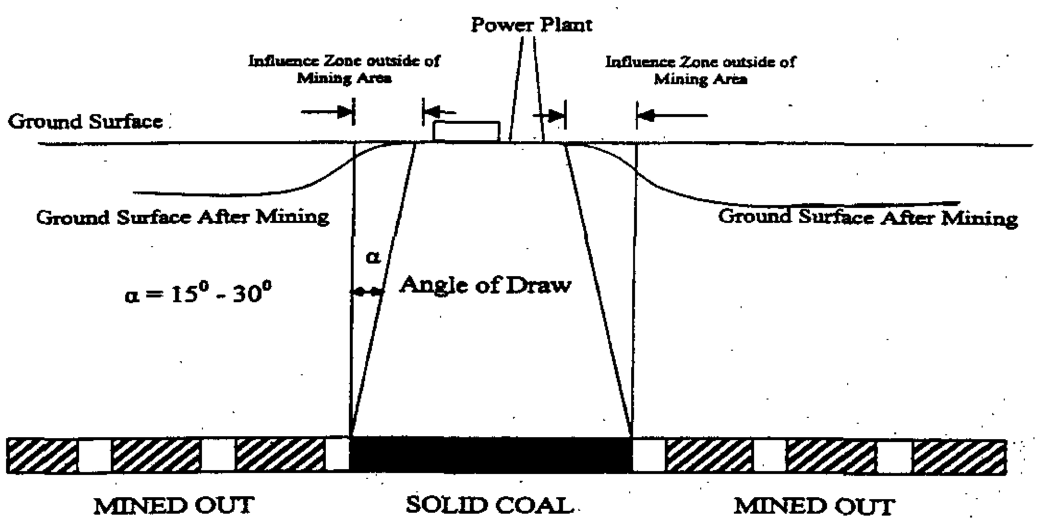

Figure 4.4.1. Subsidence concepts of Angle of Draw and Influence Zone

Following plant construction, mining would not occur beneath the project site. Therefore, damage to structures from potential surface subsidence caused by coal mine collapse would not be anticipated. To confirm the status of surface conditions prior to construction, settlement monitoring pins would be installed around the anticipated footprint of the power plant and monitored on a bi-monthly basis.

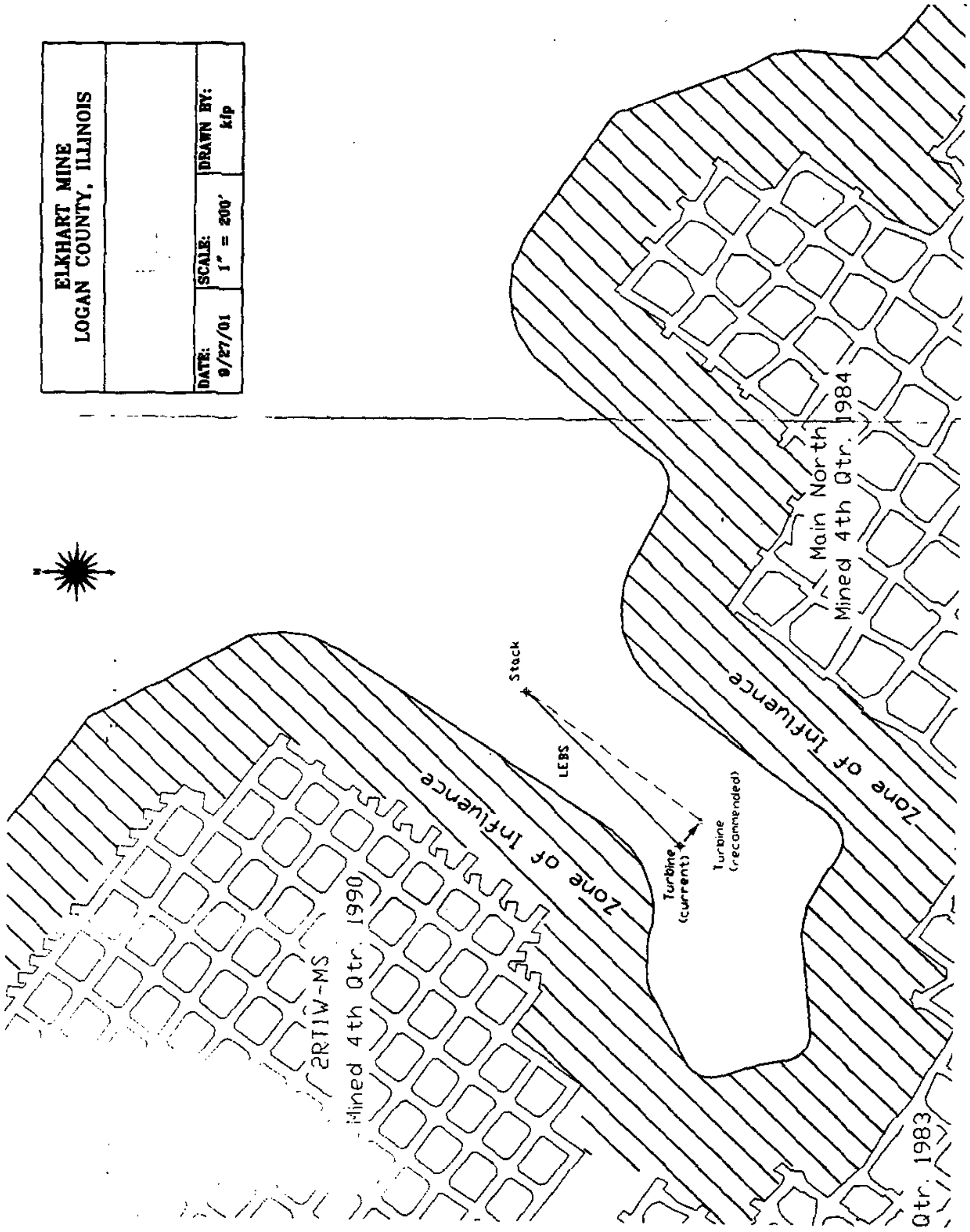

Figure 4.4.2. Influence Zone at the site proposed for the power plant

4.4.2 Soil

Construction activities would be performed in accordance with an approved erosion and sedimentation control plan. The plan would designate measures to control storm water runoff and prevent contamination of undisturbed areas during and after construction. Soil compaction and paving on approximately 3 acres of the 5 acre plant site would be required, with a resulting reduction of soil permeability and a corresponding increase in the rate at which storm water run off would occur.

Freshly mined coal contains hazardous organic compounds such as phenol, toluene, naphthalene, anthracene, and pyridine on the newly formed coal surfaces (Meyer 1977). Coal fragments and coal dust containing at least trace quantities of these organic compounds have probably deposited on soil at the 5 acre plant site, which would be adjacent to the existing facilities for coal loading onto trucks. Although not currently anticipated to be required, the plant site would be decontaminated using accepted cleanup practices prior to plant construction if hazardous organic compounds are determined to be present at unacceptable levels.

An Environmental Investigation (MWH Americas, Inc. 2002) was performed to determine the possible presence of soil contaminants at the proposed site. Sediment samples and surface soil samples were variously analyzed for volatile organic compounds (VOCs), semi-volatile organic compounds (SVOCs), pesticides, poly-chlorinated biphenyls (PCBs), and metals. Screening criteria were based on IEPA guidance for Tier I Soil Remediation Objectives for the Industrial/Commercial Worker and Construction Worker scenarios. Results were also compared to the Soil Component of the Groundwater Ingestion Exposure Route to assess the potential for chemical migration to Illinois Class I or Class II groundwater.

The only sediment samples (of 8 collected samples) containing levels of benzene that exceeded (slightly) IEPA's Soil Component of Class I Groundwater Ingestion Exposure Route were two samples obtained at the North Sediment Pond where stormwater from the raw coal storage area flows into the pond. No other VOCs exceeded the IEPA Tier I Soil Remediation Objectives. No SVOCs, pesticides, PCBs, or metals exceeded the Tier I Soil Remediation Objective. No further investigations were considered necessary.

4.5 SOLID WASTE

The proposed plant would be designed to minimize the types and quantities of hazardous materials required for plant construction and operation. Where alternatives are available, materials with reduced hazards would be selected. Hazardous bulk material storage and handling facilities (i.e., water treatment systems) would be designed with redundant containment to minimize the impact of spills. If any spills should occur, they would be neutralized manually and cleaning wastes would be removed from the site by an approved waste disposal contractor.

4.5.1 Construction

During power plant construction, non-hazardous wastes typically generated during construction activities, comprised primarily of wood, metal, plastic, concrete ingredients and components, etc., would be transported to an off-site sanitary landfill for disposal. Small amounts of hazardous wastes that may be generated during construction would be packaged in 55 gallon drums, temporarily stored on the site in a location protected from the weather, and transported to an off-site licensed hazardous waste disposal facility. Only small quantities of hazardous wastes would be involved, which would preclude any substantive constraints or non-routine requirements regarding hazardous waste management in accordance with regulations under the Resource Conservation and Recovery Act.

4.5.2 Operation

The proposed power plant would generate non-hazardous vitrified ash and gypsum. The vitrified ash would be marketed for use as a construction material (e.g., as a road base) or transported for disposal at an approved off-site location. Because a viable market would not be expected for produced gypsum, the gypsum would be transported for disposal as non-hazardous solid waste in an approved disposal location at the Turris Mine or on CBEC property.

Occasionally, clean-out of the electrostatic precipitator and the precipitator ash hoppers would be required. The volume of ash material recovered from clean-out operations and planned for disposal at the Turris Mine would be relatively small compared to the amount of combustion product waste currently accepted for disposal by Turris Coal Company in the slurry impoundment.

Used oil, waste lubricants, and small amounts of other common, maintenance-related hazardous wastes would be generated by plant operations. Primary emphasis for waste management would be devoted to waste recycling. Wastes that cannot be recycled would be temporarily stored on-site in suitable waste storage barrels. The barrels, while on-site, would be stored in an area providing secondary containment. Filled barrels would be transported by an approved waste disposal contractor to a properly licensed disposal site for the produced wastes. The quantities of hazardous waste that would be generated during the operation of the proposed power plant would be expected to be sufficiently low to qualify the plant as a "Small Quantity Generator" under Federal waste regulations.

4.6 ECOLOGICAL RESOURCES

4.6.1 Terrestrial Ecosystems

No appreciable impacts on terrestrial ecosystems at the site or in the immediate vicinity would be expected during construction or operation of the proposed power plant. The site for the new plant, which has previously been disturbed, includes portions of a mowed field (or lawn), a truck turnaround, and remnants of an old homestead. The site of the proposed 22-acre retention pond is currently used as cropland and, upon completion of the pond, would be surrounded by farming activities and coal handling and processing operations. Other than common animal species, such as rodents, shrews, and small birds, abundant wildlife does not exist on these sites. On-site activities would result in environmental conditions that would be similarly unfavorable for permanent wildlife as those existing in the immediate vicinity due to the annual cycle of crop harvest and field cultivation.

Disturbance of the state-listed natural area on Elkhart Hill (Section 3.6.1) would not be expected to result from additional groundwater withdrawals required for the proposed plant, due to both the distance from the project site and the separation from the site by an intermittent stream that provides an indication of surface water and groundwater flow in a northeasterly direction, away from Elkhart Hill. The uniqueness of this natural area is largely a result of a groundwater supply that provides moist growing conditions for flora. The aquifer that would supply water for the proposed plant (Section 4.3.2) would be obtained from a deeper formation than the near-surface aquifer that supplies Elkhart Hill. Groundwater for Elkhart Hill would be associated with either the Illinoisan Hagerstown member sand or seeps or perched water table conditions, while groundwater for the proposed plant would be obtained from the Pearl formation. Furthermore, the long-term operations of Elkhart Village well #3 since 1984 and the Turris Mine wells have not adversely affected the Elkhart Hill natural area. In addition, the static water levels in Elkhart well #3 have not declined, thus indicating a stable water balance.

The proposed new well (TH1-01) would be developed only if absolutely necessary to meet water requirements during drought conditions, and well usage would be minimal due to its poorer yield conditions compared with wells planned for development east of the project site. The primary groundwater withdrawals for the proposed project would be from alluvial deposits associated with the bottomlands of Lake Fork Creek, which is over 2 miles east of Elkhart Hill. Groundwater investigations have not indicated any connections between the lower aquifer deposits and the Elkhart Hill groundwater. Thus, additional groundwater withdrawal to support the power plant would be unlikely to affect the groundwater supply at Elkhart Hill. Any induced infiltration from the surficial aquifer supplying Elkhart Hill into the deeper aquifer as a result of increased groundwater pumping for the proposed plant would be expected to be sufficiently small that neither the surficial groundwater system beneath Elkhart Hill nor the Elkhart Hill ecosystem would be adversely affected.

4.6.2 Aquatic Ecosystems

The proposed plant would be unlikely to affect aquatic resources on or off the plant site. During and after construction of the power plant, most of the on-site water would continue to be recycled for use in coal processing or power plant operations (Section 4.3.2).

As is currently the case, discharges to off-site surface waters, such as Lake Fork Creek, would occur only during those infrequent occasions when rainfall events exceed existing pumping capacities designed to keep all water on the site. As a result, the proposed water retention pond would not produce any sustained impact on Lake Fork Creek, and the partial diversion of water during those infrequent large rainfall events would not substantially change overall flow into the Creek. Because off-site surface waters would not be used to meet water supply needs for the proposed plant, no effects from surface water withdrawal would be expected. The discharge limitations and monitoring requirements of the existing NPDES permit would continue to protect the off-site aquatic environment. The discharge requirements established in the NPDES permit should be protective of aquatic life downstream of the outfalls, given that discharges are rare and typically occur during rain events, when other runoff into the stream would further dilute the concentration of any contaminants released from the site. The concentrations of chemical constituents in water collected in on-site ponds may change during operation of the proposed power plant; however, since the ponds have little ecological significance, no adverse impact would be expected.

4.6.3 Threatened and Endangered Species

Because no threatened or endangered species are found on the plant site or in the immediate vicinity (Section 3.6.3), and because the effects of construction and operation related to protected species would be contained substantially on developed or previously disturbed land, no impacts to threatened or endangered species or their habitat would be anticipated. Consultation with the U.S. Fish and Wildlife Service (Appendix A) supports this conclusion.

4.6.4 Biodiversity

The proposed power plant would be constructed on previously disturbed property that does not support a diversity of biota. Construction and operation of the proposed power plant would not adversely impact important ecological habitat and would thus have minimal impact on biota. Therefore, the impact on biodiversity at the plant site would be negligible.

Biodiversity in areas adjacent to or in the immediate vicinity of the site proposed for the power plant, beyond the boundaries of the Turris Mine property, would not be affected by power plant operations due to the substantial absence of biodiversity resulting from regional agricultural activities.

Greater biodiversity occurs in the vicinity of Elkhart Hill, which is located about 1 mile northwest of the site proposed for the power plant. Due to the distance of separation, construction activities would not be expected to produce any effects on biodiversity at Elkhart Hill. Relative to ground-level impacts resulting from plant emissions, Elkhart Hill would be considered to be in the "near field" of the plant's air emissions. Biodiversity can potentially be affected by acid deposition resulting from power plant emissions; this deposition primarily results from two sources – from acid formed by atmospheric reactions of water with sulfates and nitrates produced from oxidation of SO_2 and NO_x or from direct emissions of sulfuric acid mist. Sulfuric acid mist could be emitted at permissible levels up to a limit of 4.1 lb/hr (Attachment A to the IEPA Construction Permit in Appendix D). The atmospheric reactions necessary to create acidic species from SO_2 and NO_x occur over time periods that would not create near-field acidic deposition events, and, in combination with the expected minimal contribution of emissions from the plant to the total quantity of acid rain precursors emitted in the State of Illinois (Section 4.2.2.3), would support a conclusion that emissions from the power plant would not adversely affect biodiversity at Elkhart Hill.

Emissions from power plant operations and conditions that could potentially affect biota around Elkhart Hill are discussed in Section 4.2.2.3.

4.7 CULTURAL RESOURCES

The proposed power plant would be unlikely to affect any historical or archaeological resources because no such resources are known to exist on the plant site. The old homestead that formerly existed at the plant site was removed years ago, and the only remaining structures are a few grain bins and a small garage. Consultation with the Illinois Historic Preservation Agency (Appendix B) confirms this finding. Any archaeological resources that might originally have been contained on land that would be affected by construction of the proposed project would have been previously disturbed by agricultural activities and by earth-moving activities during construction of the Turris Mine's surface facilities (buildings, roads, coal storage piles and silos, wastewater ponds, and combustion waste disposal areas). In the unlikely event that archaeological resources would be found during plant construction, work would be stopped immediately and an archaeologist from the Illinois Historic Preservation Agency would be notified to initiate additional consultation.

4.8 FLOODPLAINS AND WETLANDS

The proposed site for the power plant is a graded, nearly level area with an approximate elevation of 585 ft (Beittel and Darguzas 1996). The May 1943 flood of record rose to an elevation of 578.5 ft near Cornland. Because Cornland is upstream from the proposed site of the power plant, the power plant site would have experienced a water surface elevation below 578.5 ft during the May 1943 flood of record.

As described in Section 3.8, the plant site would be located in an area that has been determined to be outside the 500 year floodplain (FEMA 1988a). Flooding at the plant site would not be anticipated.

Floodplain encroachment would not occur because the proposed plant would not be constructed on the floodplain of Lake Fork Creek. The plant site would be located approximately 2 miles west of Lake Fork Creek and more than 6 ft above the estimated 50- to >100-year floodplain. Urbanization and industrialization in this rural area are minimal, and encroachment along Lake Fork Creek would be unlikely. Comparison of data from the May 1943 flood with the instantaneous peak water surface elevation of 578.2 ft experienced in the period from 1948 to 1995, as a result of the April 1979 flood, indicates that the water surface rose by about 0.3 ft in response to a flow increase of 20,070 ft^3/s (9 MM gpm). Minimal increase in elevation of the flood water surface occurred because a large land area was available for the water after overbanking had occurred. A large channel cross section resulted from the low topographic relief in the vicinity of the site and the fact that the ground surface is relatively flat with few prominent features.

Construction and operation of the proposed power plant would not result in any stream diversions that would alter existing off-site drainage patterns. The land immediately surrounding the new plant would be appropriately sloped to promote drainage away from structures.

Because the only wetland resources close to the proposed site are along the edges of the Turris Mine ponds and the unnamed ditch, which have little, if any, ecological value, no impacts to wetlands would be expected. Appendix C provides copies of correspondence resulting from consultations with state and Federal agencies on the topic of surface water resources.

4.9 SOCIOECONOMICS

Construction of the proposed power plant would create an average of approximately 100 and a peak of about 180 temporary construction jobs in the Elkhart area. Subsequent operation of the plant would create approximately 45 new permanent jobs – 25 for power plant operation and maintenance and 20 for coal mining to provide the additional output required to supply coal to the new power plant.

4.9.1 Population

4.9.1.1 Construction

The following analysis uses the maximum number of 180 construction workers as an upper bound for evaluating potential impacts. Nearly all of the 180 construction workers would be expected to be obtained from the labor force in the area surrounding Elkhart. The cities of Springfield, Decatur, Normal, Bloomington, and Peoria are each within commuting distance of the proposed site and have available workers with the skills necessary to build the proposed plant. For this reason, any in-migration of construction workers to Logan County and the Elkhart area would likely be minimal. To establish a reasonable upper bound for analysis purposes, however, approximately 25% of the construction workforce (45 workers) were assumed to relocate to Logan County during the 24 month construction period.

Based on past experience with construction projects in similar areas, about 60% of the in-migrating workforce (27 workers) would be expected to be accompanied by families and 40% (18 workers) would relocate alone. If the 27 workers who were assumed to bring their families to Logan County would have an average family size of 2.94, the same as for those families currently residing in the county (U.S. Census Bureau 2000), a temporary increase of 97 persons (or 0.31%) would result in Logan County's population. These new residents would probably locate in Elkhart, Lincoln, or other towns and unincorporated areas. However, because of the small number of in-migrating construction workers, no substantive impact on the local area would be expected.

In addition to those workers directly involved in plant construction, a number of indirect jobs would be created in service industries as a result of construction-related expenditures. Based on past experience with construction projects in similar areas, an additional 90 indirect jobs would be expected to result from plant construction. However, only a portion of the indirect jobs would be in Logan County because many construction workers would be expected to live elsewhere and thus contribute to the creation of indirect jobs outside of Logan County. Regardless of their location, all of the indirect jobs, which would typically require less skill and training than would construction jobs, could be readily filled by current residents without any requirements for additional in-migration of workers.

4.9.1.2 Operation

As indicated previously in Section 4.9, an expected 45 new permanent jobs would be created during operation of the power plant – 25 for plant operation and maintenance and 20 for coal mining. Because plant operations would last considerably longer than construction, commuting from outside the immediate area would be less attractive to many workers and, consequently, a higher proportion of plant workers would be likely to reside in Logan County. Some of the 45 new jobs could be filled by existing residents, while others would be filled by people who would be willing to commute from residences outside the county. For analysis of operations impacts, a level of 50% (23 workers) of the operations period jobs was projected to be filled through in-migration of workers to Logan County.

Based on past experience with startup of new plant operations, approximately 75% of the new Logan County residents (17 workers) would be accompanied by families, with the remaining 25% (6 workers) in-migrating alone. If the 17 workers who would be expected to bring their families to Logan County would have an average family size of 2.94, Logan County's population would grow by 56, or 0.18%. As during the construction period, the small number of new residents would probably locate throughout the towns and unincorporated areas of the county and would have a minimal impact on the local area.

In addition to the 45 workers directly involved in plant operations and related mining, an estimated 23 indirect jobs would be created, but all of these jobs would be expected to be filled by current residents rather than in-migrants.

4.9.2 Employment and Income

4.9.2.1 Construction

If the proposed power plant is built, the number of construction jobs in Logan County would increase by a maximum of approximately 180 and unemployment would decline slightly. This increase would approximately double the number of construction jobs in the county but would be only temporary. In addition, some portion of the 90 indirect jobs created from power plant construction would be filled by Logan County residents, which would contribute to a lowering of the local unemployment rate. Because construction jobs are relatively high paying, average per capita income in the county would probably rise slightly during this period.

4.9.2.2 Operation

During power plant operations, the number of permanent jobs in Logan County would increase by approximately 45, with 25 of the new positions for power plant operators and maintenance personnel and 20 for coal miners. As during the construction period, a slight decline in the local unemployment rate would result. In addition, a portion of the 23 indirect jobs created from plant operations would be filled by residents of Logan County, which would slightly reduce unemployment.

4.9.3 Housing

4.9.3.1 Construction

The 45 new households that would be created in Logan County to support power plant construction could be easily accommodated by existing housing. The 759 vacant units (Table 3.9.3) in

Logan County provide substantial options to new residents wishing to buy or rent; accordingly, no adverse impacts on local housing would be expected.

4.9.3.2 Operation

The 23 new households created in Logan County to support power plant operations would be easier to accommodate than would households required by in-migrating construction-period workers. Thus, no adverse impacts would be expected.

4.9.4 Public Services

4.9.4.1 Construction

The short-term influx of 97 new people in 45 households during the construction period would not be expected to strain the capacity of Logan County's public service systems. As described in Section 3.9.4, a number of sewer and water systems are located throughout the county, and the outlying areas also are capable of accommodating new residents through the use of wells and septic systems. Accordingly, the relatively small increase in demand for services caused by project-induced in-migrants during construction would not be expected to have an appreciable adverse effect on the local area.

Based on the county average of 0.78 school-age children per family (U.S. Census Bureau 2000), the 27 in-migrating construction workers that would be accompanied by their families would add 21 children to the Logan County schools. This small number of new students could easily be absorbed by the many public and parochial schools in Logan County without any noticeable adverse effect.

4.9.4.2 Operation

Because the larger number of in-migrants during the construction period would not be expected to create adverse impacts on the county's ability to provide water and sewer services, the 56 new residents in 23 households anticipated during power plant operations would clearly not lead to adverse effects.

The relocation of 17 operations workers and their families would require Logan County schools to accommodate an additional 13 children. No noticeable adverse impact would be expected.

4.10 HUMAN HEALTH

This section focuses on potential health impacts to the public. During construction of the power plant, impacts to the public would result mainly from noise and dust generated by construction activities and from vehicular accidents that could potentially occur due to increased traffic. Noise impacts are discussed in Section 4.12; traffic impacts are discussed in Section 4.13; and air quality issues are addressed in Section 4.2.

During operation, public health effects could result from exposures to toxic chemicals through various routes, including airborne (inhalation) exposures, exposures to contaminated water or food sources, and direct contact exposures. Airborne emissions from the proposed power plant would include SO_2, NO_x, particulate matter, heavy metals, and organic compounds. However, maximum ambient air concentrations from the proposed plant would be well below levels of concern (Section 4.2).

A potential supplier of aqueous ammonia required for operation of the selective catalytic reduction unit planned for use in controlling NO_x emissions from the proposed plant is located approximately 2 miles from the site proposed for the power plant. The aqueous ammonia required by the plant would probably be purchased from this nearby supplier. Approximately 5,000 gallons of ammonia solution would be stored on the site. The storage and use of aqueous ammonia during normal operations would not be expected to have an appreciable impact on the air or water environments because no intentional releases to the atmosphere would occur. Ammonia in the aqueous solution used by the plant for controlling NO_x emissions would be converted to elemental nitrogen and water.

An accident involving aqueous ammonia leakage or release would provide the only mechanism that could result in a potentially significant off-site impact. Because the distance to the nearest resident would be about 4,000 ft from the plant site (Section 3.11), no need for evacuation would be expected even with worst-case conditions. Under accident conditions, travel might need to be restricted along Township Road 600N (Figure 2.1.2). Before construction and operation of the proposed power plant, a procedure would be developed to comply with OSHA, EPA, and State of Illinois requirements regarding Hazardous Substances and Chemical Accident Prevention regulations. Pursuant to the Emergency Planning and Community Right-to-Know Act of 1986, the power plant would be required to establish and provide Material Safety Data Sheets and other emergency planning information covering all materials and chemicals planned for use to state and local emergency planning committees.

A health hazard could potentially result from catastrophic failures of plant facilities, which might occur during sufficiently severe weather events. The plant would be located in an area that can experience tornadoes, heavy snow, and severe thunderstorms. To protect against failures caused by natural events, the plant and ancillary equipment would be designed using engineering standards that would provide weather-related protection and using building codes appropriate for Logan County and central Illinois. In addition, the plant would be equipped with a modern control system capable of safely responding to weather events that could potentially result in adverse effects on plant operations.

Atmospheric releases from the proposed power plant would provide the major potential source of exposure to hazardous substances. The other potential exposure pathways (i.e., food, water, and direct contact) would have a low potential because the pathways are not complete. For example, any liquid discharges and solid wastes with potential for creating health hazards would be sent to settling ponds at the Turris Mine. All ash would be recycled to the combustion unit, calcined during combustion, and removed from the system as vitrified bottom ash. Uptake through food sources would be negligible because the only pathway would be from atmospheric deposition, and the air analysis (Section 4.2) demonstrated that air concentrations at receptor locations would be small and that deposition onto soils, for potential uptake by plants, or directly onto edible parts of plants, would be even smaller.

Electrical power transmission lines produce electromagnetic fields. The Turris Mine currently receives electricity from transmission lines, and the proposed power plant would tap into the existing lines. New transmission lines and towers would only be required to connect a new transformer for the power plant with an existing substation on the Turris Mine property. The new lines and towers would be confined to the mine property. Electricity marketed from the power plant would use the existing transmission lines.

The issue of electromagnetic fields potentially affecting human health has received increased interest over the last decade. The National Radiological Protection Board (1992) has stated: "The epidemiological findings that have been reviewed provide no firm evidence of the existence of a carcinogenic hazard from exposure of paternal gonads, the fetus, children, or adults to the extremely low frequency electromagnetic fields that might be associated with residence near major sources of electricity supply, the use of electrical appliances, or work in the electrical, electronic, and telecommunications industries." Because the proposed power plant would require no new off-site transmission lines and because the nearest residences would be located about 4,000 ft from the mine boundary, the power plant would not be expected to change the existing level of effects, if any.

In summary, no appreciable impacts to public health would be anticipated from construction and operation of the proposed power plant.

4.11 WORKER SAFETY

Workers would be protected during both construction and operation through compliance with OSHA regulations and company policies and procedures, as described below.

4.11.1 Construction

An average of approximately 100 workers would be employed during construction of the power plant. Physical hazards associated with plant construction would be considered standard industrial hazards. Construction workers would be protected through compliance with OSHA's *Safety and Health Regulations for Construction* (29 CFR 1926) and the corporate procedures of CBEC and Turris Coal Company, as appropriate.

In 1993, approximately 47 disabling injuries were reported for every 1,000 workers in the U.S. construction industry. Most accidents and injuries resulted from overexertion, falls, or being struck by equipment (NSC 1994). Assuming the same injury rate at the proposed power plant, approximately 10 injuries would statistically be expected to occur during the 24-month construction period for the power plant. Construction-related illnesses could also occur from exposures to chemical substances, but rates for standard construction are low and none would be expected during construction of the proposed power plant.

4.11.2 Operation

Potential impacts to workers during plant operation would be expected to be limited to standard industrial hazards associated with operation of a coal-fired power plant. No unusual situations would make operation of the proposed power plant more hazardous than normal power plants. Programs would be developed to minimize employee health and safety risks during operation. Safety programs would cover all aspects of OSHA compliance, employee safety and health, industrial hygiene, and fire protection, prevention, and training, as described in 29 CFR 1910, *Occupational Safety and Health Standards*. Physical hazards to workers during operation could include, but are not limited to, equipment accidents, noise, heat stress, and confined spaces. OSHA provisions have been established and successfully applied in industrial operations to mitigate these types of safety hazards.

4.12 NOISE

Ambient noise would increase both during construction and operation of the proposed power plant. During construction, noise would be intermittent and would vary with different activities, such as ground clearing and excavation. Earthwork and associated activities would result in generation of noise from operation of vehicles and heavy equipment. Maximum noise levels from such activities typically range from 85 to 90 dB(A) at a distance of about 50 ft from the source (EPA 1978). Noise from construction could be above background for the rural area immediately outside the Turris Mine's boundaries, and some sounds could be perceptible and distinct to the nearest residents (about 4,000 ft from the plant site). Such noises might include backup alarms on trucks and any impact noises, such as those associated with pile drivers. However, sound levels decrease by 6 dB for each doubling of the distance from the source if no absorption of sound energy occurs. Therefore, expected noise levels from construction of the proposed power plant would be less than 54 dB(A) at a distance of 3,000 ft from the site. EPA (1978) has identified 55 dB(A) as a yearly average noise level that, if not exceeded, would avoid activity interference and annoyance. In addition, noise impacts from power plant construction would be minimized because construction activities would occur mostly during daylight hours and would not be continuous.

During power plant operations, noise would be produced from the boiler building, turbines, fans, generators and transformers, and cooling tower fans. Based on similar sized units (DOE 1995), sound levels at 1,000 ft to 1,500 ft would be approximately 45 dB(A) and at 4,000 ft would decrease to below 35 to 40 dB(A). Thus, under most circumstances, the nearest residents should not experience any annoyance from noise produced during power plant operation. Under unusually quiet circumstances, a general background hum may be perceptible, but such low noise levels should be below levels of annoyance. Periodic short-duration operational events, such as blowdowns that produce elevated noise levels, may be restricted to daytime hours to minimize effects.

4.13 TRAFFIC

During the peak construction period, up to 180 new workers in passenger vehicles would travel to and from the proposed power plant on a daily basis. In addition, peak construction-related truck traffic would total 75 round-trips per day during the pouring of concrete foundations for the plant. During plant operations, a maximum of 45 daily round-trips by new plant operators, maintenance workers, and miners would be required. New truck traffic during this period would be less than during plant construction, amounting to a maximum of 35 daily round-trips for the delivery and removal of materials. If all of the trucks used for deliveries would also remove materials, the total number of new daily round-trips by trucks during power plant operations would be reduced.

Existing on-site and off-site transportation corridors have sufficient capacity to handle the expected increase in traffic during construction and operation of the proposed power plant. Increased truck traffic would follow commercial or designated routes already used and appropriate for truck traffic. Periodic deliveries of liquid ammonia from the likely supplier (Section 4.10) would also be made in approved containers using commercial or designated routes and properly placarded vehicles. Township Road 600N (Figure 2.1.2), which would provide access to the proposed site, is a wide, two-lane paved road that currently experiences no congestion (Section 3.12). Because Township Road 600N has easily accommodated a daily workforce of 240 in the past, the addition of up to 180 daily round-trips by construction workers and up to 75 trucks per day for hauling construction materials would not be expected to substantially diminish the road's ability to accommodate traffic requirements. Because the proposed plant would have a separate entrance from Township Road 600N, no interference with coal trucks being loaded on the Turris Mine property would be anticipated.

The number of worker vehicles and trucks traveling to and from the plant site during operations would be substantially less than during the construction period; thus, no adverse impacts to traffic flow on Township Road 600N would be expected. Truck traffic during operations would be associated primarily with the delivery of ammonia and limestone and with the transport of vitrified ash and gypsum from the site for sale or disposal. No special designation would be required to deliver ammonia for the power plant on roads in Logan County (R. Fox, Logan County Highway Engineer, personal communication to M. Schweitzer, ORNL, June 9, 1998). If necessary due to unavailability of markets for vitrified ash, a conveyor would be installed to move ash from the power plant to the Turris Mine's waste disposal ponds, which would reduce on-site traffic and traffic crossing Township Road 600N.

Traffic accidents during deliveries of plant feedstocks or removal of plant products could potentially result in releases of chemical materials into the environment. The primary solid materials of interest would limestone, vitrified ash, and gypsum, each of which is non-hazardous in nature. Any accidental spillage of these materials would be contained and readily cleaned for disposal by personnel using appropriate protective equipment, such as eye protection and protection from airborne dust particles.

Ammonia requirements for the NO_x control system planned for the power plant would be transported to the site as an aqueous solution with a maximum ammonia concentration of 19%. Ammonia solutions containing ammonia at concentrations greater than 10% are corrosive. Skin contact with such solutions can result in burns, and ingestion can be fatal. Accidental spills would require isolation to avoid contact by unprotected persons. Containment and recovery would require hazardous material-trained personnel using personal protective equipment (respirators and impervious clothing). Residues should be diluted with water and neutralized with dilute acid. The neutralized spill would require final cleanup through absorption on clay, sand, earth, or other inert substance and packaging in a suitable container for disposal. Ammonia in an aqueous solution at the low concentration planned for use would vaporize slowly from the aqueous solution if spilled and either dissipate into the atmosphere or be absorbed by materials that it contacts; potentially hazardous vapor clouds of ammonia would not be formed.

Limestone would be transported to the site in an aggregate form, with particle sizes ranging in diameter from 1 to 4 inches. The limestone would be off-loaded from trucks into a covered, three-wall enclosure and stored until crushed and slurried. Any spillage of the limestone chunks would be cleaned-up as quickly as practical.

Vitrified ash would present little spill risk and would be transported off-site after being crushed to a consistent size range for easy handling. Any spill of this material would pose no threat to the environment and would be cleaned-up as quickly as practical.

Gypsum transported from the plant would possess sufficient moisture to avoid atmospheric release. If spilled, gypsum would not threaten the environment but would be cleaned-up as quickly as practical.

4.14 LAND USE

The proposed power plant would produce minimal adverse impacts on land use. The power plant would be constructed and operated within the boundaries of the Turris Mine's property. The land uses of property surrounding the proposed plant site are agricultural and industrial. The proposed power plant would be accessed by existing roads and would be located on 5 acres of industrial property owned by Turris Coal Company. An additional 22 acres of land that is currently leased for agricultural cultivation would be used for constructing a water retention pond.

The 5-acre site proposed for the power plant would border the northern side of Township Road 600N and is currently designated as the emergency coal storage area for the mine (Beittel and Darguzas 1996) (Figure 2.1.4). The site contains a paved loop road that is used by truck traffic to access the mine's coal loading facilities and a mowed grassy field that has, to date, not been required to provide emergency coal storage for the mine. The site has been partially disturbed by truck traffic on the loop road, and both the truck loading operations and the proximity of the site to the coal mine have probably resulted in deposition of coal fragments and coal dust onto the soil. The 22-acre property proposed for the retention pond would be removed from corn and soybean production. Based on the large amount of land in Logan County that is used for corn (about 180,000 acres) and soybean (about 165,000 acres) production, the impact of removing from crop production acreage that accounts for approximately 0.01% of the land devoted to production of these two crops in Logan County would be negligible.

Construction and operation of the proposed power plant would be consistent with the existing use of on-site property and facilities for coal mining but would contrast with the agricultural uses occurring on surrounding off-site lands. The 5-acre parcel of land for the power plant would be transformed from a well maintained, seldom used field into an industrial site, and the 22 acres of cropland would be transformed from crop production into a retention pond. The Turris Mine would not be impacted because 248 acres of mine property would remain unused for mining-related operations and available for designation of an alternative, similar-sized area (e.g., 5 acres) for emergency coal storage.

Operation of the proposed power plant would require a collective total of approximately 5 acres of additional land surface beyond the Turris Mine property to provide infrastructure support for the power plant. Land that is currently used for agricultural purposes, primarily for growing corn and soybeans, would need to be purchased or leased for the new wells near Lake Fork Creek, access roads to the wells, and rights-of-way/easements to the plant site for well water and natural gas delivery lines.

Operations at the Turris Mine would continue in a normal manner following initiation of power plant construction and operation. Permits for the Turris Mine would continue to be required from the Illinois Department of Mines and Minerals, the Illinois Environmental Protection Agency, the Illinois Department of Transportation, the Mine Safety and Health Administration, the Illinois Department of Natural Resources, and the Bureau of Alcohol, Tobacco, and Firearms.

4.15 ENVIRONMENTAL JUSTICE

The analysis in Section 4.10 (Human Health) indicates that no adverse health effects to any individuals or households present in the vicinity of the proposed power plant would be expected. In addition, because the percentages of minorities and low-income households in Elkhart are less than those in Logan County and Illinois (Section 3.14), no disproportionate adverse effects on low-income or minority populations would be expected.

4.16 POLLUTION PREVENTION MEASURES

The proposed power plant would include pollution prevention measures that would be developed and implemented as part of the plant design or in response to potential or actual impacts identified during construction and operation of the plant. Pollution prevention measures are discussed in Sections 2.0 and 4.0 and summarized in Table 4.16.1.

Table 4.16.1. Pollution prevention measures developed for the LEBS power plant

Environmental issue	Pollution prevention measure
Aesthetics	• Dust suppression measures (i.e., watering) would be used to minimize the occurrence of fugitive dust during construction period excavation and earthwork.
Air quality	• The proposed power plant would demonstrate improvements in pollutant reduction levels compared with current coal-fired electric power generation. Concentrations of SO_2, NO_x, and PM_{10} in exhaust gases would be below applicable standards for pollutant emissions.
	• Dust suppression measures (i.e., watering) would be used to minimize emissions of particulate matter during construction period excavation and earthwork.
Water use and quality	• The proposed power plant would result in no net consumption of non-potable water from the mine's recirculating water distribution system, which draws water from ponds fed by storm water runoff.
	• During operation of the proposed power plant, most on-site water, whether originating from groundwater or precipitation, would continue to be recycled for use in coal processing or would be used in power plant operations.

Table 4.16.1. Pollution prevention measures developed for the LEBS power plant

Environmental issue	Pollution prevention measure
	• The implementation of an erosion and sedimentation control plan, a spill prevention and control plan, and standard engineering practices would minimize potential impacts to surface waters and groundwater. • Land occupied by and immediately surrounding the proposed power plant would be appropriately sloped to promote drainage away from structures.
Groundwater withdrawal	• Groundwater monitoring, which currently occurs at the mine site, would continue, and the effects of operating new wells developed for the proposed power plant would be monitored. • Groundwater quality at the Elkhart municipal well would continue to be monitored by the village in accordance with state regulations. • The effects of aquifer drawdown would be minimized or avoided by using field drainage runoff collected in a retention pond, and groundwater obtained from up to 6 new wells would be used to support power plant operations, especially during periods of extended drought. • With the monitoring program in place, warning indications of lowering water levels or deterioration in groundwater quality would result in implementation of measures to avoid adverse impacts. If potential for an adverse effect on groundwater levels supporting nearby private or municipal water supply wells should be determined to exist as a result of groundwater pumping for the proposed power plant, deepening or replacement of wells and/or replacements of pumps would be used to avoid occurrences of any impacts. Prompt action in response to adverse trends observed during monitoring would be expected to allow sufficient time to implement protective measures, since water levels would drop gradually. • Pumping of groundwater at the existing Turris Mine's wells and at the proposed wells would set up a zone of capture to entrain any seepage from surface impoundments. The zone of capture would minimize impacts to the village of Elkhart's municipal groundwater well from activities occurring at the mine and the power plant.
Solid waste management	• Fly ash from the electrostatic precipitator would be recycled to the combustor to maximize ash discharge in the form of vitrified bottom ash, which would be a marketable by-product for use in road construction. • Gypsum waste and any fly ash that could not be sold commercially would be transported for disposal as solid waste at an appropriately permitted landfill site at the Turris Mine or on CBEC property.
Aquatic ecosystems	• The existing outfall at the Turris Mine, through which new drainage from the proposed power plant would be discharged, would continue to be monitored.

Table 4.16.1. Pollution prevention measures developed for the LEBS power plant

Environmental issue	Pollution prevention measure
	• Discharge limitations and monitoring requirements of the existing National Pollutant Discharge Elimination System permit would continue to be enforced for protecting the off-site aquatic environment.
Traffic	• If necessary, a conveyor would be installed to move vitrified ash from the proposed power plant to the waste disposal ponds, which would reduce on-site traffic and traffic crossing Township Road 600N.
	• Carpooling would be encouraged.
Applicable permits and regulations	• Compliance and consultation requirements pertaining to the proposed power plant would help to ensure that potential impacts would be minimized or avoided (e.g., U.S. Fish and Wildlife Service consultation, work stoppages if cultural resources should be discovered, and compliance with all applicable Federal, state, and local environmental regulations).

5.0 IMPACTS OF COMMERCIAL OPERATION

Following the completion of a 6 month demonstration period, two commercial operating scenarios would be reasonably foreseeable outcomes: (1) a successful demonstration followed immediately by commercial operation of the power plant at approximately the same power level or (2) an unsuccessful demonstration followed by modification of the plant equipment, possibly including additional post-combustion emission controls, to improve operational performance and economics. Under either scenario, the expected operating life of the power plant would be 35 years. Impacts associated with the second scenario would be nearly identical to those in the first scenario, with the exception that the power plant would not operate for a period of time during which construction and installation of the new equipment would result in minor impacts. Because both scenarios would eventually result in a power plant that would be permitted to operate in an environmentally acceptable manner, the long-term impacts would be similar and the remainder of this discussion focuses on commercial operation of the power plant, assuming a successful demonstration.

The proposed power plant would be a baseload electric generating station that operates 24 hours per day; therefore, the level of short-term impacts during commercial operation would not change from those described for the demonstration in Section 4.0. For long-term effects, the types and levels of impacts would be expected to be identical to those discussed in Section 4.0, except for impacts that accumulate with time.

During commercial operation, the proposed power plant would burn about 350,000 tons of coal per year from the Turris Mine, which would require about a 17% increase from the current production rate of the mine. Existing reserves owned by Turris Coal Company are available for over 30 years of mining at the current production rate; additional reserves are available to Turris Coal Company for supporting the ability of the mine to supply coal to the power plant for the anticipated 35 years of commercial operation.

Coal combustion by-products from commercial operation of the power plant, if not marketable, would be transported for disposal at a permitted location either on Turris Mine property or on CBEC property. Disposal at a CBEC site would result in additional traffic to transport waste materials to the permitted disposal location. Disposal on Turris Mine property could be accomplished for the expected 35 year life of the proposed power plant using permitted combustion waste disposal facilities.

Commercial operation of the power plant would increase the potential for groundwater withdrawals to occur during an extended drought. Consequently, the potential for the power plant to adversely affect the municipal water supply or water quality for the village of Elkhart would increase. The measures identified in Table 4.16.1 and discussed in Section 4.3.2 would be used to avoid or minimize adverse effects on local water supplies or quality.

6.0 CUMULATIVE EFFECTS

This section presents the potential impacts on resource areas resulting from other facilities, operations, and activities that, in combination with potential impacts from the proposed power plant, may contribute to cumulative impacts. Because the proposed site is relatively isolated, the potential for cumulative impacts to most resources would be low. Except for atmospheric resources, which can be affected by sources of air emissions throughout the region, the adjacent Turris Mine is the only existing facility or source of environmental impact that has been identified as potentially contributing to cumulative impacts. The mine has not contributed to any known adverse cumulative effects since operations began in 1982. Because the cumulative effects of the proposed power plant and the coal mine would be intertwined, their impacts were described in Section 4.0, which also contained descriptions of the cumulative impacts of regional and global sources of air emissions on atmospheric resources.

As indicated in Table 3.9.1, the population in Elkhart, IL, declined by 6.7% from 1990 to 2000; the population in Logan County declined by 2% from 1980 to 2000, although the 2000 population showed an increase of 1.3% since 1990. The lack of a substantial growth trend for population is reasonable based on the agricultural nature of the area. Farm acreage in Logan County increased by 3% from 1992 to 1997, and 82.1% of the County is devoted to crop production (Farmland 1997). Based on this population trend and the fact that land surrounding Turris Coal Company property is used for agriculture, groundwater use for municipal or individual needs would not be expected to substantially change in the foreseeable future. Thus, cumulative impacts for groundwater availability and quality would be expected to be limited to the impacts from addition of the proposed power plant to local usage, as documented in this EIS.

Two projects associated with the Turris Mine might be constructed independently of the proposed power plant (i.e., two projects might be constructed regardless of the outcome of the proposed project). For the first project, Turris Coal Company has received a permit for coal combustion waste disposal on 92 acres of land, which would consist of 72 acres for solid waste disposal immediately to the north and east of the proposed project and 20 acres immediately to the west of the proposed project for a sedimentation pond and soil stockpiles. The Turris Mine would receive coal ash from industrial coal users for disposal at this site. Potential users could include A. E. Staley and ADM; both companies have corn processing facilities in Decatur that produce ash from burning coal to generate steam and energy. The new site would supplement the existing 265 acres of mine property used for disposal of combustion waste. This 35% increase in land use for waste disposal would not create unique or new environmental issues. Waste management and handling would be consistent with methods that have historically been used for managing combustion waste at the site, and Turris Coal Company would continue to monitor for groundwater contamination and leaching from the waste disposal areas. To date, no environmental contamination or degradation of groundwater quality has resulted from the existing waste disposal activities; extension of the management methods used for the existing waste disposal areas to the new site would be expected to result in similar environmental results and in avoidance of adverse cumulative effects.

Because 270 acres are currently available on Turris Coal Company's property, the cumulative use of 119 acres (92 acres for a new waste disposal sites, 5 acres for the proposed power plant, and 22 acres for the proposed retention pond) would not alter the currently approved land use activities. Disturbances to ecological habitat would be similar to those described in Section 4.6. If constructed, coal ash for the new waste disposal site would be delivered by trucks. No additional truck traffic would be required because the ash would be delivered in trucks that currently transport coal from the Turris Mine to industrial facilities and return empty to the mine. Therefore, no cumulative impacts would be expected from traffic congestion or noise.

The second project would comprise construction of a railroad spur to the Turris Mine from the Union Pacific rail line, which passes within 2 miles of the mine (Figure 2.1.2). The railroad spur would be used to transport about 2 train shipments of coal per week from the mine and would be located immediately west of the site proposed for the power plant. The railroad spur would not disturb a large amount of land, disrupt ecological habitat, or cause traffic congestion. The infrequent noise associated with train movement should not cause appreciable impacts.

No other existing or proposed facilities, operations, or activities have been identified that may contribute to cumulative impacts. Although Turris Coal Company actively pursues new customers for coal from the Turris Mine, which could increase the rate of coal mining, no appreciable changes in the mining rate have been confirmed for the foreseeable future. (S. Fowler, Former Manager of Engineering, Turris Coal Company, personal communication to R. Miller, ORNL, March 31, 1998; and G. Gaar, Economic Development Director, Logan County, personal communication to R. Miller, ORNL, March 31, 1998). Thus, increased coal production from the Turris Mine, beyond the need for increased production to support the proposed power plant, would not be a foreseeable contributor to cumulative effects.

7.0. REGULATORY COMPLIANCE AND PERMIT REQUIREMENTS

Table 7.1.1 displays the Federal, state, and local regulatory compliance and permit approval requirements for the proposed power plant. NEPA support and compliance documents that have been prepared include an environmental questionnaire prepared by Babcock Borsig to provide basic information for use in preparing this EIS and in supporting implementation of the NEPA process, a water supply study performed for Corn Belt Energy Corporation by the Farnsworth Group, and a Subsidence Report prepared by Southern Illinois University. Other required support and compliance documents would include an environmental monitoring plan that Babcock Borsig would subsequently prepare, as appropriate, if the proposed action is implemented by DOE. For issues governed by both Federal and state requirements, the state generally has primacy with Federal oversight. If any state regulation is less stringent than a corresponding Federal regulation, the Federal agency can require compliance with the more stringent Federal regulation.

Under Section 7 of the Endangered Species Act of 1973 (Public Law 93-205, as amended), DOE must consult with the U.S. Fish and Wildlife Service to ensure that proposed actions would not jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of the critical habitat of such species. Appendix A documents consultations with the U.S. Fish and Wildlife Service.

Under Section 106 of the National Historic Preservation Act (Public Law 89-665, as amended), DOE must consult with the Illinois Historic Preservation Agency (HPA) to ensure compliance with the act. Appendix B documents the Illinois HPA's findings from such consultation.

Table 7.1.1. Federal, state, and local permits and approvals required for the proposed plant

Anticipated permitting agency	Permit or approval
	Federal
U.S. Environmental Protection Agency	• Acid Rain Compliance Plan and Permit Application, Phase II, for compliance with the Clean Air Act regarding nitrogen oxides and sulfur dioxide emissions and allowances
	• Certification of Continuous Emission Monitoring System (CEMS) for operation of a CEMS, requiring accuracy, calibration, response, and other CEMS testing information
Federal Aviation Administration (and Illinois Department of Transportation, Division of Aeronautics)	• Determination of Obstruction Hazard for construction of tall structures, requiring locations and dimensions of stacks and other tall structures
U.S. Fish and Wildlife Service	• Endangered Species Act; Section 7 consultation

Table 7.1.1. Federal, state, and local permits and approvals required for the proposed plant

Anticipated permitting agency	Permit or approval
	State
Illinois Environmental Protection Agency, Division of Air Pollution Control	• Prevention of Significant Deterioration Permit for construction of a major source of air pollution, requiring air emissions and control equipment data, air quality modeling, Best Available Control Technology determination, and on-site air quality monitoring data • Title IV Acid Rain Permit • Title V Operating Permit for operation of a major source of air pollution, requiring emissions information, descriptions of emissions points, plot plan/layout/process flow drawings, and reasonably anticipated operating scenarios
Illinois Environmental Protection Agency, Division of Water Pollution Control	• National Pollutant Discharge Elimination System (NPDES) Permit, for discharges into surface water, requiring locations, volumes, and pollutant concentrations of expected wastewater discharges • NPDES General Stormwater Permit, construction and operation, for stormwater runoff from industrial areas and from construction on areas of five or more acres, requiring a Storm Water Pollution Prevention Plan containing site description, pollution and erosion control measures, and maintenance procedures
Office of State Fire Marshal	• Above Ground Storage Tank Permit for construction of above-ground oil and chemical storage tanks, requiring plans and specification of tanks and on-site inspections
Illinois Historic Preservation Agency	• Historic Preservation Approval for construction of industrial site, requiring site plans • *National Historic Preservation Act; Section 106 consultation*
Illinois Department of Nuclear Safety	• Registration of Radioactive Material for possession or installation of generally licensed radioactive material, such as fuel flow or fly ash level sensing devices, requiring device registration information
	Local
Local Planning Board	• Approval of Site Plan for construction of industrial facility, *requiring site arrangement drawing and description of proposed* power plant
Local Highway Agency	• Highway Permit for connection of plant access road to township road, requiring access road drawing and construction and traffic control plans
Local Building Codes Agency	• Building/Plumbing Permit for construction of occupied building and indoor plumbing facilities, requiring site arrangement drawings and building and/or plumbing plans

8.0 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

For construction and operation of the proposed power plant, some resource commitments would be irreversible and irretrievable; that is, the resources used would be neither materials that would be obtained from renewable sources nor resources that would later be recoverable for future uses. Resources that would be irreversibly and irretrievably committed for construction and operation of the proposed power plant would consist of a small area of vegetation and associated habitat that would be developed for constructing the plant, construction materials that would not be recovered or recycled, and fuel and sorbent that would be consumed or reduced to unrecoverable forms of waste.

Resources committed for construction of the proposed power plant would include crushed stone, sand, water, diesel fuel, gasoline, and iron ore used in producing the steel required for the plant. Resources committed for plant operations would include coal, natural gas, aqueous ammonia, limestone sorbent, and water. Except for groundwater, abundant supplies of all resources committed for the proposed plant would be readily available. Groundwater commitments could potentially result in adverse impacts from aquifer drawdown and groundwater quality degradation. These potential effects would be partially offset by groundwater withdrawal from multiple wells with sufficient separation to avoid connected impacts on groundwater levels and by monitoring drawdown and water quality to detect, and correct as necessary, any trend that could result in adverse impacts. Water that evaporates would be lost locally but would be recycled to the atmosphere.

The proposed power plant would require a commitment of human and financial resources that would eliminate availability of these resources for alternative projects or Federal activities. However, this commitment would be consistent with the purpose and need for the proposed action (Section 1.0).

9.0 THE RELATIONSHIP BETWEEN SHORT-TERM USES OF THE ENVIRONMENT AND LONG-TERM PRODUCTIVITY

The proposed power plant would occupy about 5 acres of land and consume a variety of natural resources, including coal, natural gas, and groundwater. A water retention pond to support operation of the proposed plant would use about 22 acres of land surface, and additional small areas totaling up to 5 acres of land may be required for monitoring wells, groundwater production wells, and other plant infrastructure-supporting operations. The plant would generate air emissions and solid wastes. However, no off-site surface waters would be used to meet water needs, and water would continue to be recycled for on-site use. Runoff discharges to off-site surface waters would occur only during infrequent occasions when appreciable rainfall events exceed the capacities of pumps designed to retain all water on the site.

The long-term benefit of the proposed LEBS project would be demonstration of an environmentally sound and innovative technology for the utilization of coal. LEBS technology would be expected to achieve appreciably lower emissions and higher electrical generation efficiencies than conventional pulverized-coal fired boilers with conventional flue gas desulfurization controls, while maintaining or lowering overall operating costs and reducing the volume of generated solid waste. The design size for the proposed power plant (91 MW) would be sufficiently large to provide convincing evidence that the technology, once operationally demonstrated at the proposed site in Elkhart, Illinois, could be readily replicated using similar sized or larger combustors, without further scale-up to verify operational or economic performance. Therefore, although the proposed plant would consume resources and generate emissions and solid wastes, the technology to be demonstrated would reduce resource consumption and waste generation in comparison with traditional pulverized coal-fired power generating technologies.

For future commercial installations of the LEBS technology, a reasonable size facility would be about 400 MW. Conventional pulverized-coal boilers used today by electric utilities are predominantly units in the range of 250 to 400 MW. Electric utilities traditionally have installed units of such size and would be expected to continue this practice, which minimizes the capital and operating costs of generating electricity (Charles and Rezaiyan 1997). Scale-up from the proposed 91 MW power plant to a 400 MW facility would be feasible without a larger-scale demonstration. However, a supercritical steam cycle operating at 4,500 psi and 1,100°F could be used with a 400 MW commercial version of the technology to further enhance operating efficiency; supercritical steam turbines are not available below a size of about 100 MW. In addition, a moving-bed, *copper-oxide sorption system* for SO_2 capture could be used in a commercial-scale LEBS facility; this technology is not yet sufficiently mature for use in the proposed demonstration project.

A 400 MW commercial version of the LEBS technology would be expected to reduce SO_2 emissions to 0.1 lb/MM Btu, which is one-twelfth of the current New Source Performance Standard of 1.2 lb/MM Btu. The rate of NO_x emissions would be expected to be approximately 0.1 lb/MM Btu, which is one-fifth and one-sixth, respectively, of the New Source Performance Standards of

0.5 lb/MM Btu for subbituminous coal and 0.6 lb/MM Btu for bituminous coal and anthracite. The technology would lower emissions of fly ash and other particulate matter to 0.01 lb/MM Btu, which is one-third of the allowable New Source Performance Standard of 0.03 lb/MM Btu.

A 400 MW version of the LEBS technology would also be expected to improve electrical generation efficiency to as high as 42% from the current level of about 35%. A low-temperature heat-recovery system, in which the flue gas temperature is lowered by transferring heat to combustion air and feedwater, would contribute to the higher efficiency. The supercritical steam cycle that could be used with a 400 MW commercial version of the technology would provide an even greater efficiency, which would reduce the quantity of coal needed to generate a given amount of electricity and, consequently, result in less emissions of CO_2 compared with conventional coal-fired facilities. The cost of electricity from LEBS technology would be expected to be about 10% less than the cost of electricity from a conventional coal-fired power plant.

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Technical Responsibility: Cultural Resources, Socioeconomic Resources, Transportation, Environmental Justice
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M.S., 1978, Planning, University of Tennessee
Years of Experience: 22
Total Publications: 50

NEPA DISCLOSURE STATEMENT FOR PREPARING AN ENVIRONMENTAL IMPACT STATEMENT ON THE LOW EMISSION BOILER SYSTEM PROOF-OF-CONCEPT PROJECT

CEQ Regulations at 40 CFR 1506.5(c), which have been adopted by the DOE (10 CFR 1021), require contractors who will prepare an EIS to execute a disclosure specifying that they have no financial or other interest in the outcome of the project. The term "financial interest or other interest in the outcome of the project" for purposes of this disclosure is defined in the March 23, 1981 guidance "Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations." *46 FR 18026–18038 at Questions 17a and b.*

"Financial or other interest in the outcome of the project" includes "any financial benefit such as a promise of future construction or design work in the project, as well as indirect benefits the contractor is aware of (e.g., if the project would aid proposals sponsored by the firm's other clients)." 46 FR 18026–18038 at 1803.

In accordance with these requirements UT-Battelle, LLC (COMPANY NAME) hereby certifies as follows:

Fill in either (a) or (b)

(a) UT-Battelle, LLC (COMPANY NAME) has no financial or other interest in the outcome of the Low Emission Boiler System Proof-of-Concept Project.

(b) ______ (COMPANY NAME) has the following financial or other interest in the outcome of the Low Emission Boiler System Proof-of-Concept Project and hereby agrees to divest itself of such interest prior to initiating any technical analysis in support of this project.

Financial or Other Interests

1.
2.
3.

Certified by:

David Rice 12/12/02

SIGNATURE DATE

David C. Rice

NAME

Director, Contracts

TITLE

14.0 INDEX

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APPENDIX A

CONSULTATION LETTERS UNDER SECTION 7 OF THE ENDANGERED SPECIES ACT

United States Department of the Interior

IN REPLY REFER TO:
FWS/RIFO

FISH AND WILDLIFE SERVICE
Ecological Services
Rock Island Field Office
4469 48th Avenue Court
Rock Island, Illinois 61201
Tel: 309/793-5800 Fax: 309/793-5804

March 8, 2001

Douglas Mulvey
Harza Engineering Company, Inc.
Sears Tower
233 South Wacker Drive
Chicago, Illinois 60606-6392

Dear Mr. Mulvey:

We have reviewed your February 19, 2001, request for information concerning any impacts to federally listed threatened or endangered species as a result of a proposed coal-fired generating plant to be built near Elkhart, Logan County, Illinois. We have the following comments.

To facilitate compliance with Section 7(c) of the Endangered Species Act of 1973, as amended, Federal agencies are required to obtain from the Fish and Wildlife Service *information concerning any species, listed or proposed to be listed, which may be present in* the area of a proposed action. Therefore, we are furnishing you the following list of species which may be present in the concerned area:

Classification	Common Name	Scientific Name	Habitat
Endangered	Indiana bat	*Myotis sodalis*	Caves, mines (hibernacula); small stream corridors with well developed riparian woods; upland forests (foraging)

The endangered Indiana bat (*Myotis sodalis*) could potentially occur throughout the state in Illinois. During the summer, the Indiana bat frequents the corridors of small streams with well developed riparian woods as well as mature upland forests. It forages for insects along the stream corridor, within the canopy of floodplain and upland forests, over clearings with early successional vegetation (old fields), along the borders of croplands, along wooded fencerows, and over farm ponds and in pastures. It has been shown that the foraging range for the bats varies by season, age, and sex and ranges up to 81 acres (33ha). It roosts and rears its young beneath the loose bark of large dead or dying trees. It winters in caves and abandoned mines.

Douglas Mulvey 2

An Indiana bat maternity colony typically consists of a primary roost tree and several alternate roost trees. The use of a particular tree appears to be influenced by weather conditions (temperature and precipitation). For example, dead trees found in more open situations were utilized more often during cooler or drier days while interior live and dead trees were selected during periods of high temperature and/or precipitation. It has been shown that pregnant and neonatal bats do not thermoregulate well and the selection of the roost tree with the appropriate microclimate may be a matter of their survival. The primary roost tree, however, appears to be utilized on all days and during all weather conditions by at least some bats. Indiana bats tend to be philopatric, i.e., they return to the same roosting area year after year.

Suitable summer habitat in Iowa and Illinois is considered to have the following characteristics within a ½ mile radius of the project site:

1) forest cover of 15% or greater;
2) permanent water;
3) one or more of the following tree species 9 inches diameter at breast height (dbh) or greater: shagbark and shellbark hickory that may be dead or alive, and dead bitternut hickory, American elm, slippery elm, eastern cottonwood, silver maple, white oak, red oak, post oak, and shingle oak with slabs or plates of loose bark;
4) at least 1 potential roost tree per 2.5 acres;
5) potential roost trees must have greater than 10% coverage of loose bark (by visual estimation of peeling bark on trunks and main limbs).

If the project site contains any habitat that fits the above description, it may be necessary to conduct a survey to determine whether the bat is present. If Indiana bats are known to be present, they must not be harmed, harassed or disturbed when present. Minor alterations of Indiana bat habitat (i.e. clearing) may be accomplished between the dates of October 1 and March 31. Large-scale habitat alterations within known or potential Indiana bat habitat should not be permitted without a bat survey and/or Section 7 consultation.

The Corps of Engineers is the Federal agency responsible for wetland regulation, and we recommend that you contact them for assistance in delineating the wetland types and acreage within the project boundary. Priority consideration should be given to avoid impacts to wetland areas. Any future activities in the study area that would alter wetlands may require a Section 404 permit. Unavoidable impacts will require a mitigation plan to compensate for any losses of wetland functions and values. The U.S. Army Corps of Engineers, Clock Tower Building, P.O. Box 2004, Rock Island, Illinois, 61201, should be contacted for information about the permit process.

These comments provide technical assistance only and do not constitute the report of the Secretary of the Interior on the project within the meaning of Section 2(b) of the Fish and Wildlife Coordination Act, do not fulfill the requirements under Section 7 of the Endangered Species Act, nor do they represent the review comments of the U.S. Department of the Interior on any forthcoming environmental statement.

Douglas Mulvey 3

Thank you for the opportunity to provide comments early in the planning process. If you have any additional questions or concerns, please contact Heidi Woeber of my staff.

Sincerely,

Wayne K. Fischer
for Richard C. Nelson
Supervisor

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HARZA HARZA ENGINEERING COMPANY, INC.
WATER & ENVIRONMENT

July 11, 2001

Mr. Richard C. Nelson, Supervisor
United States Department of Interior
Fish and Wildlife Service
4469 48th Avenue Court
Rock Island, Illinois 61201

NO OBJECTION
U.S. Fish & Wildlife Service
Rock Island, Illinois
Supervisor Date 9/6/01

Subject: Threatened and Endangered Species Review
Cornbelt Energy Corporation Coal-Fired Generating Plant

Dear Mr. Nelson:

In response to your letter dated March 8, 2001 (included as Attachment 1), we provide the following information to support our conclusion that the proposed site identified for the Prairie Energy Power Plant near Elkhart does not have the suitable summer habitat for the Indiana bat. Your correspondence indicated that the following habitat characteristics were required within a ½ mile radius of the project site:

1. forest cover of 15% or greater;
2. permanent water;
3. one or more of the following tree species 9 inches diameter at breast height (DBH) or greater: shagbark and shellbark hickory that may be dead or alive, and dead bitternut hickory, American elm, slippery elm, eastern cottonwood, silver maple, white oak, red oak, post oak, and shingle oak with slabs or plates of loose bark;
4. at least 1 potential roost tree per 2.5 acres;
5. potential roost trees must have greater than 10% coverage of loose bark (by visual estimation of peeling bark on trunks and main limbs).

Figure 1 shows the general location of the proposed power plant and retention reservoir. Figure 2 shows a recent aerial photograph of the site. Site photographs are provided in Attachment 2 and referenced below. The proposed retention reservoir location is and has historically been used for agricultural row crop production (Pictures 1 and 2). No trees are located on the proposed retention reservoir site. The proposed power plant site will be located adjacent to existing coal mine structures. In general, the footprint of the power plant will impact areas that are currently maintained lawn (Pictures 3, 4, and 5 and an old farm site that is now owned by the coal mine (Pictures 6 and 7). Four mature trees (three Siberian Elms and one Silver Maple) are located at the old farm site. Areas within ½ mile of the proposed sites are either industrial or agricultural.

As can be seen from the attached photographs and Figure 2, the proposed site and areas within ½ mile of the site do not contain over 15% forest cover and therefore does not meet the habitat characteristics provided above. We ask that you provide a response concurring with our conclusions that the proposed site does not contain suitable habitat for the Indiana bat.

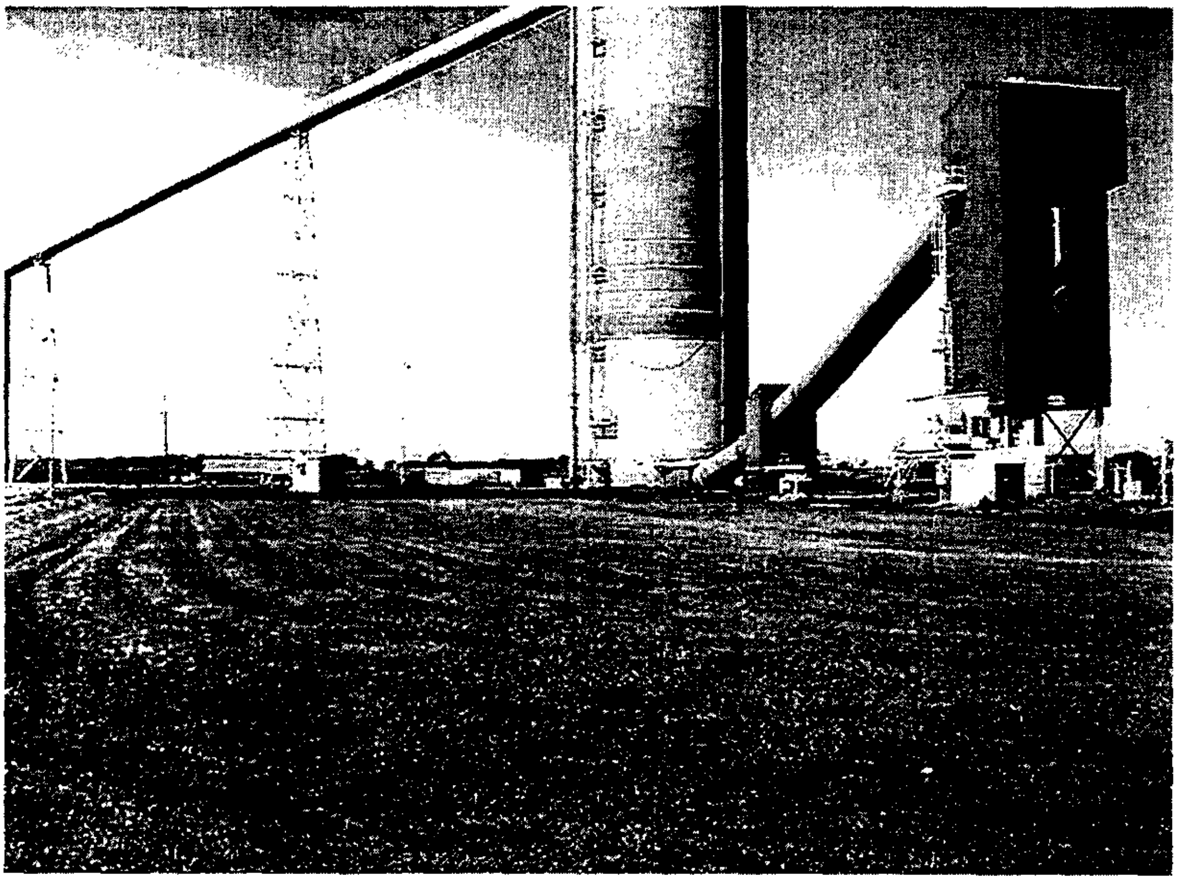
Sears Tower 233 South Wacker Drive Chicago, Illinois 60606-6392 Tel: 312.831.3000 Fax: 312.831.3999 Web: www.harza.com

If you have questions, please contact me at (312) 831-3859 or Joyce Coffee at (312) 831-3856. Thanks for your assistance.

Very truly yours,

Douglas L. Mulvey, P.E.
Environmental Engineer

Photo accompanying letter dated July 11, 2001, to Mr. Richard C. Nelson, United States Department of Interior, as evidence that the site location does not meet the habit requirements of the Indiana Bat.

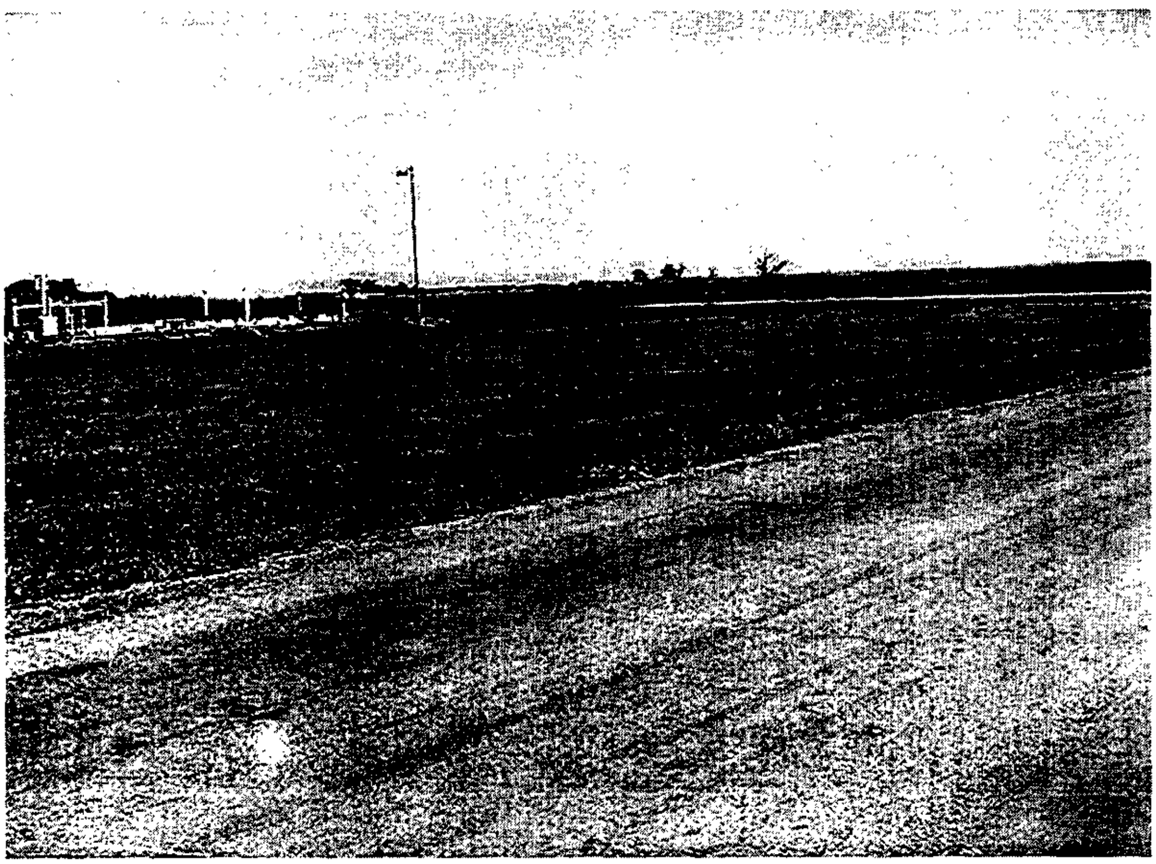


Proposed Site Looking Southwest
(Existing Coal Load Out Silo)

Photo accompanying letter dated July 11, 2001, to Mr. Richard C. Nelson, United States Department of Interior, as evidence that the site location does not meet the habit requirements of the Indiana Bat.

Proposed Site Looking Southeast

Photo accompanying letter dated July 11, 2001, to Mr. Richard C. Nelson, United States Department of Interior, as evidence that the site location does not meet the habit requirements of the Indiana Bat.



Proposed Site Looking North

APPENDIX B

CONSULTATION LETTERS UNDER SECTION 106 OF THE NATIONAL HISTORIC PRESERVATION ACT

HARZA

HARZA ENGINEERING COMPANY, INC.
WATER & ENVIRONMENT

February 19, 2001

Ms. Anne Haaker
Deputy State Historic Preservation Officer
Illinois Historic Preservation Agency
1 Old State Capitol Plaza
Springfield, Illinois 62701-1507

Subject: Permitting Pre-application Coordination
Cornbelt Energy Corporation Coal-Fired Generating Plant

Dear Ms. Haaker:

Harza Engineering Company (Harza) has been retained by Cornbelt Energy Corporation (Cornbelt) of Bloomington, Illinois to provide permitting support for a proposed coal-fired generating plant (Facility) to be built near Elkhart, Illinois in Logan County (Figure 1). I would like to request information on historic, architectural or archaeological sites within the project site as identified on the attached figure to determine compliance with Section 106 of the National Historic Preservation Act of 1966.

The Facility will have a gross plant output of 89.5 MW and will be located adjacent to and interface with an existing coal mined operated by the Turris Coal Company. The Facility will obtain water from existing onsite storage ponds, field tile drains, and groundwater wells. A water retention pond will also be designed to hold the 30-day plant water demand (1500 gpm). The pond will be built in an upland location (agricultural field) approximately 800 feet to the west of the proposed Facility (Figure 1). Conceptual designs show the pond to be 670 feet by 975 feet from interior toe of embankment to interior toe of embankment. The pond depth will be 13 feet. An additional two feet of freeboard is provided.

Field tile drain water, to be used by the Facility, will come from a broken tile drain located on the southeast corner of the property (Figure 1). A sump and pump is currently located at this location for mine usage; but, a new sump and pump works is proposed to pump this water into the new retention pond located on the north part of the site. Excavation and construction of a new sump could impact the small grassed waterway that flows through this location (Figure 1).

If you have any questions or require additional information, please call me at (312) 831-3859 or email me at dmulvey@harza.com. Thanks for your help.

Very truly yours,

Douglas Mulvey
Environmental Engineer

Enclosures: Figure 1

Sears Tower 233 South Wacker Drive Chicago, Illinois 60606-6392 Tel: 312.831.3000 Fax: 312.831.3999 Web: www.harza.com

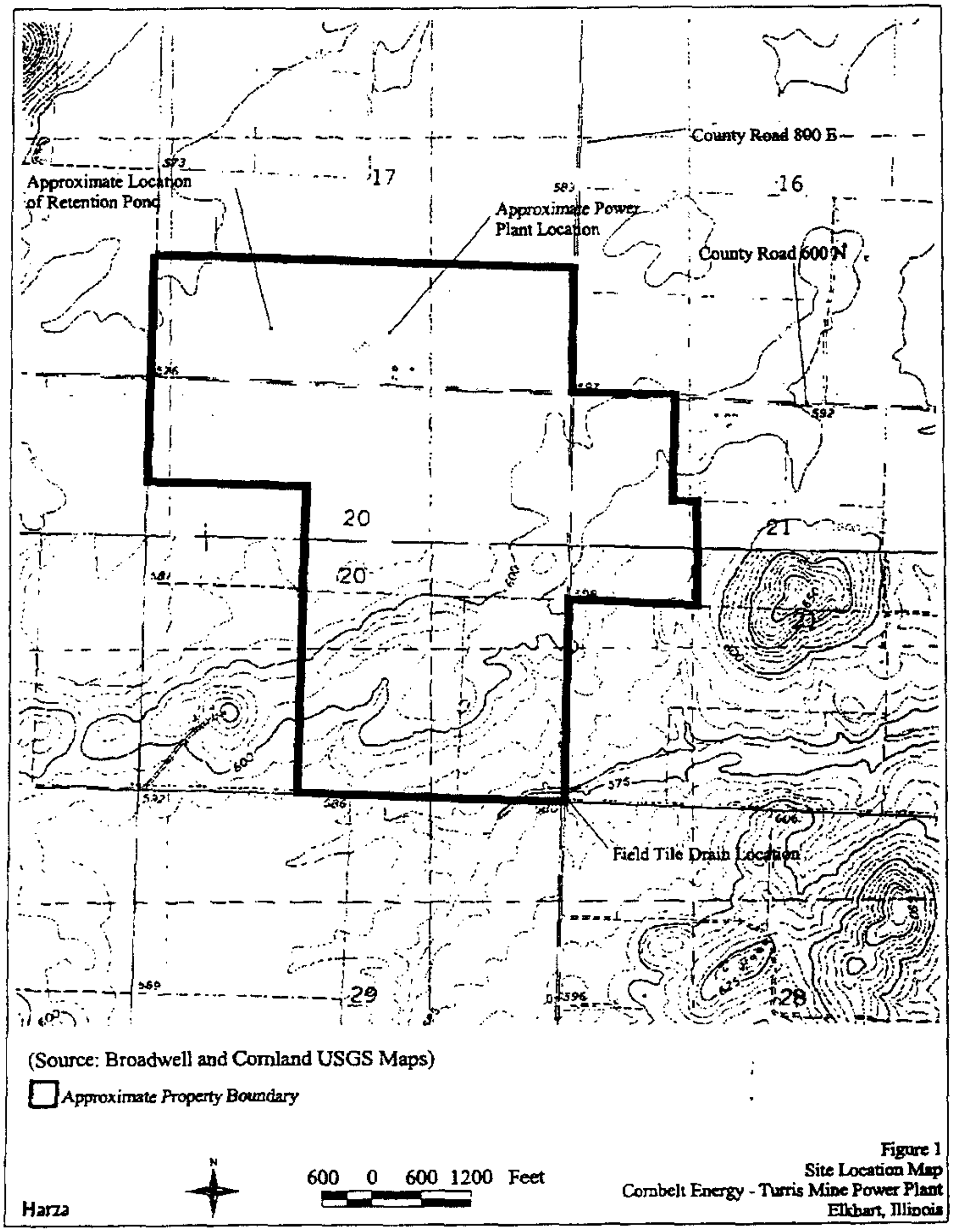


Figure 1
Site Location Map
Cornbelt Energy - Turris Mine Power Plant
Elkhart, Illinois

Illinois Historic Preservation Agency

1 Old State Capitol Plaza • Springfield, Illinois 62701-1507 • (217) 782-4836 • TTY (217) 524-7128

Logan County Please refer to: IHPA LOG #0102200039HLO
Elkhart
Turris Mine Power Plant
Proposed Coal-Fired Generating Plant

March 20, 2001

Doug Mulvey
Harza Engineering Company, Inc.
Sears Tower
233 South Wacker Drive
Chicago, IL 60606-6392

Dear Sir:

Thank you for requesting comments from our office concerning the possible effects of the project referenced above on cultural resources. Our comments are required by Section 106 of the National Historic Preservation Act of 1966 (16 USC 470), as amended, and its implementing regulations, 36 CFR 800: "Protection of Historic Properties".

The project area has not been surveyed and may contain prehistoric/historic archaeological resources. Accordingly, a Phase I archaeological reconnaissance survey to locate, identify, and record all archaeological resources within the project area will be required. This decision is based upon our understanding that there has not been any large scale disturbance of the ground surface (excluding agricultural activities) such as major construction activity within the project area which would have destroyed existing cultural resources prior to your project. If the area has been heavily disturbed prior to your project, please contact our office with the appropriate written and/or photographic evidence.

The area(s) that need(s) to be surveyed include(s) all area(s) that will be developed as a result of the issuance of the federal agency permit(s) or the granting of the federal grants, funds, or loan guarantees that have prompted this review.

Enclosed you will find an attachment briefly describing Phase I surveys and a list of archaeological contracting services. THE IHPA LOG NUMBER OR A COPY OF THIS LETTER SHOULD BE PROVIDED TO THE SELECTED PROFESSIONAL ARCHAEOLOGICAL CONTRACTOR TO ENSURE THAT THE SURVEY RESULTS ARE CONNECTED TO YOUR PROJECT PAPERWORK.

If you have any further questions, please contact Eric G. Hansen at 217/785-4998.

Sincerely,

Anne E. Haaker

Anne E. Haaker
Deputy State Historic
Preservation Officer

AEH:EGH:jw

Enclosure: Archaeology Contractor List

MWH
MONTGOMERY WATSON HARZA

November 21, 2001

Ms. Anne Haaker
Deputy State Historic Preservation Officer
Illinois Historic Preservation Agency
1 Old State Capitol Plaza
Springfield, Illinois 62701-1507

Subject: **Phase I Archaeological Survey – Turris Mine Power Plant**
IHPA Log # 0102200039HLO

Dear Ms. Haaker:

In response to your letter dated 20 March 2001, Corn Belt Energy Corporation retained Cultural Resource Services to perform a Phase I Archaeological Survey on the proposed project area. Enclosed please find two copies of the Archaeological Reconnaissance Survey for the 90-acre tract in which a retention pond will be constructed to provide water supply to the proposed power generation facility.

Note that the location of the retention pond has changed since our letter dated 19 February 2001, and the new location is to the east of County Road 800 E. The enclosed reconnaissance survey provides a map with the new location.

If you have any questions or require additional information, please call me at (312) 831-3859 or email me at douglas.l.mulvey@mwhglobal.com.

Very truly yours,

Douglas Mulvey, P.E.
Senior Environmental Engineer

Enclosures : Two copies – Archaeological Reconnaissance Survey

Sears Tower
233 South Wacker Drive, Suite 900
Chicago, Illinois
60606-6392

Tel: 312 831 3000
Fax: 312 831 3889

Delivering Innovative Projects and Solutions Worldwide

Cultural Resource
Services

November 16, 2001

Ms. Noelle Ferguson
MWH Americas, Inc.
Sears Tower
233 South Wacker Drive
Chicago, IL 60606

Re: Archaeological Reconnaissance Survey of a 90-acre Tract in Section 21, T18N, R3W in Logan County, Illinois.

Dear Ms. Ferguson:

Enclosed are three copies of the Archaeological Survey Short Report for the above referenced project. Two copies of the report need to be sent to the Illinois Historic Preservation Agency for review, and one copy is for your files. No sites, or archaeological material, were found during the survey and project clearance has been recommended.

Also enclosed is the invoice for this project. Thank you for using Cultural Resource Services. I have conducted archaeological surveys and investigations in 83 of Illinois' 102 counties and will be happy to provide you with estimates for projects located anywhere in Illinois. Please call me if you have any questions.

Sincerely,

David J. Halpin

P.O. Box 7104
Springfield, Illinois 62791
(217) 793-1805

ARCHAEOLOGICAL SURVEY SHORT REPORT
Illinois Historic Preservation Agency
Old State Capitol, Springfield, Ill.
62701 (217) 785 4997

Reviewer: ______
Date: ________
__Accepted __Rejected

IHPA Log # Pending

Locational Information and Survey Conditions

County: Logan
Quadrangle: Cornland and Broadwell (1982; 1980) **Project Type/Title:** Archaeological Reconnaissance Survey for a Proposed Retention Pond in Logan County, Illinois.

Funding and/or Permitting Federal/State Agencies: IEPA

Location: NW align: NW1/4, NW1/4, and SW1/4, NW1/4, and W1/2, W1/2, SE1/4, NW1/4 Section 21 T18N R3W 3rd PM

U.T.M.: NW corner: 4431000N 291560E to 4430990N 291960E to 4430580N 291920E to 4430580N 292020E to 4430190N 292010E to 4430200N 219540E

Project Description: The project area is a 90-acre tract currently used as an agricultural field.

Topography: Uplands

Soils: Tama-Ipava-Sable Association.

Drainage: Lake Fork of Salt Creek

Land Use/Ground Cover: The project area is located in a fall plowed soybean field. The ground surface was well washed and visibility ranged from 50-90 percent at the time of the survey.

Survey Limitations: None

Archaeological and Historical Information

Historical Plats/Atlases/Sources: No structures, or improvements, are depicted in the project area on the 1823 GLO plat, on the 1864 county map, or in the 1873, 1893, and 1910 county atlases (Burhans and Snyder 1864; USGLO 1823 Vol.16: 18; Windmill Publications 1990).

Previously Reported Sites: No sites have been recorded within one mile of the project area. Several sites have been recorded along the Lake Fork of Salt Creek, some 1.5 miles east of the project area.

Previous Surveys: Surveys #217 and #8667 were conducted for the coalmine located immediately west of the project area. No other surveys have been recorded within one mile of the project area.

Regional Archaeologist Contacted: Self

Investigation Techniques: Pedestrian survey in 5m intervals.

Time Expended: 28 person hrs.

Sites/Find Spots Located: None

Cultural Material: None

Collection Technique: N/A

Curated at: N/A

Area Surveyed: 90 acres (364230 square meters)

Sources Cited

Burhans, S.H., and L.M. Snyder
1864 *Map of Logan County, Illinois.* Chicago, author.

United States Department of Agriculture
1982 General Soil Map of Illinois. Agricultural Experiment Station, University of Illinois, in cooperation with the Soil Conservation Service, United States Department of Agriculture, Washington, DC.

United States General Land Office
1823 Survey Map of Township 18 North, Range 3 West, 3rd PM. Microfilm.

Windmill Publications, Inc.
1990 *Combined 1873, 1893, 1910 Atlases of Logan County, Illinois.* Mt. Vernon, Indiana.

RESULTS OF INVESTIGATIONS AND RECOMMENDATIONS:

✓ Phase I Archaeological Reconnaissance Has Located No Archaeological Material; Project Clearance Is Recommended.

____ Phase I Archaeological Reconnaissance Has Located Archaeological Materials: Site(s) Does (Do) Not Meet Requirements For National Register Eligibility; Project Clearance Is Recommended.

____ Phase I Archaeological Reconnaissance Has Located Archaeological Materials; Site(s) May Meet Requirements For National Register Eligibility; Phase II Testing Is Recommended.

____ Phase II Archaeological Investigation Has Indicated That Site(s) Does (Do) Not Meet Requirements For National Register Eligibility; Project Clearance Is Recommended.

____ Phase II Archaeological Investigation Has Indicated That Site(s) Meet Requirements For National Register Eligibility; Formal Report Is Pending And A Determination Of Eligibility Is Recommended.

Comments:

Archaeological Contractor Information:

Archaeological Contractor: Cultural Resource Services
Address/Phone: PO Box 7104
Springfield, Illinois 62791
(217) 793-1805

Surveyor: David J. Halpin
Report Completed By: David J. Halpin
Submitted By:

Survey Date: 11/9, 12, 13, 14/2001
Date: 11/16/2001

David J. Halpin
Cultural Resource Services

Attachment Check List:

✓ 1) USGS Topographic Map
✓ 2) Project Map
N/A 3) Site Form (Two copies)
✓ 4) Relevant Correspondence
✓ 5) Additional Information Sheets

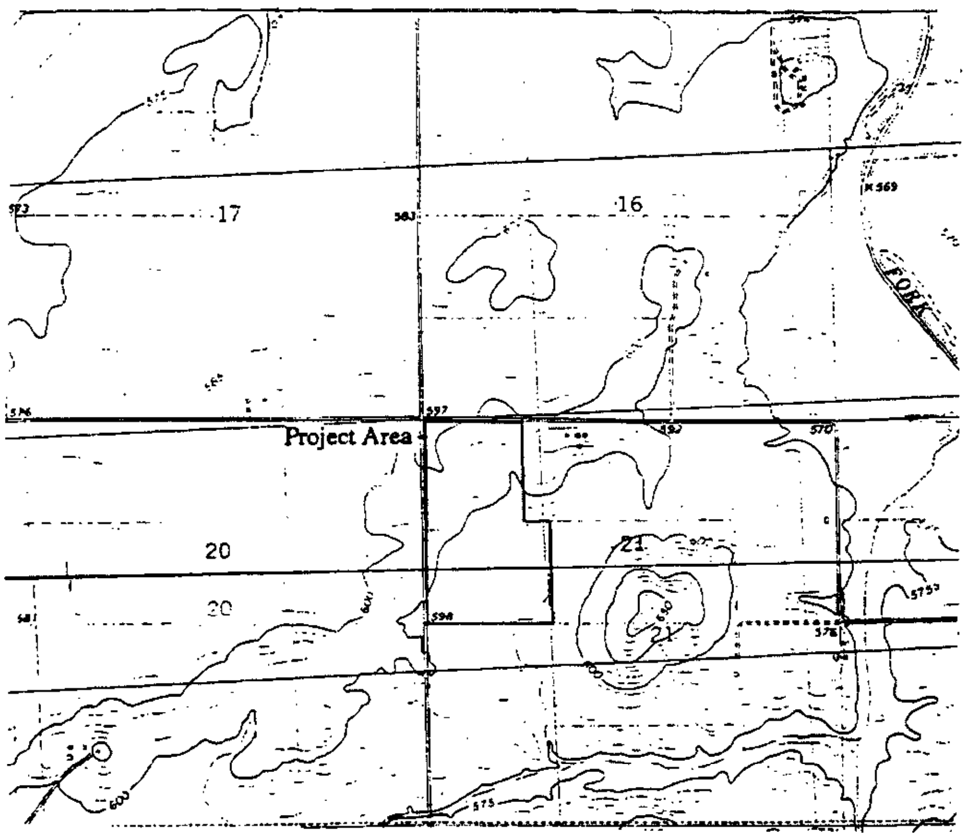
Address of Owner/Agent/Agency To Whom SHPO Comment Should Be Mailed:

Montgomery Watson Harza
Americas Inc.
Sears Tower
233 South Wacker Drive
Chicago, IL 60606

Contact Person: Ms. Noelle Ferguson 312-831-3044

Reviewers Comments:

CORNLAND AND BROADWELL, ILLINOIS QUADRANGLES
7.5 minute series (1982; 1980)



Project Area

1 .5 0 1 KILOMETER

MWH
MONTGOMERY WATSON HARZA

December 20, 2001

Mr. Eric G. Hansen
Illinois Historic Preservation Agency
500 E. Madison Street
Springfield, Illinois 62701

Subject: **Phase I Archaeological Survey – Turris Mine Power Plant**
IHPA Log # 0102200039HLO

Dear Mr. Hansen:

In response to our phone conversation on 19 December 2001, the attached map (Figure 1) clarifies the areas within the Turris Coal Company property that will be disturbed as a result of the proposed project. The proposed project includes construction of the Prairie Energy Power Plant (Power Plant) and a process water retention pond.

The area disturbed as a result of the Power Plant construction is located in the southern portion of Section 17 as outlined in red in Figure 1. This area was surveyed on 4 August 1998 (IHPA Log # 980326005PLO).

The process water retention pond will be constructed in the parcel east of east of County Road 800 E (see Figure 1). This area is included in the 90-acre tract surveyed by Cultural Resource Services on 16 November 2001. The Archaeological Reconnaissance Survey for the tract was submitted to the IHPA on 21 November 2001.

The process piping associated with the water retention reservoir is anticipated to be constructed along the ditch adjacent to the County and Township roads. This area has been previously disturbed due to road construction and associated grading.

It is our understanding that we have provided the required information for IHPA approval of the proposed project. If you have any questions or require additional information, please call me at (312) 831-3044 or email me at noelle.ferguson@mwhglobal.com.

Very truly yours,

L Noelle Ferguson

L. Noelle Ferguson
Environmental Engineer

Enclosures : Figure 1

Sears Tower
233 South Wacker Drive, Suite 900
Chicago, Illinois
60606-6392

Tel: 312 831 3000
Fax: 312 831 3889

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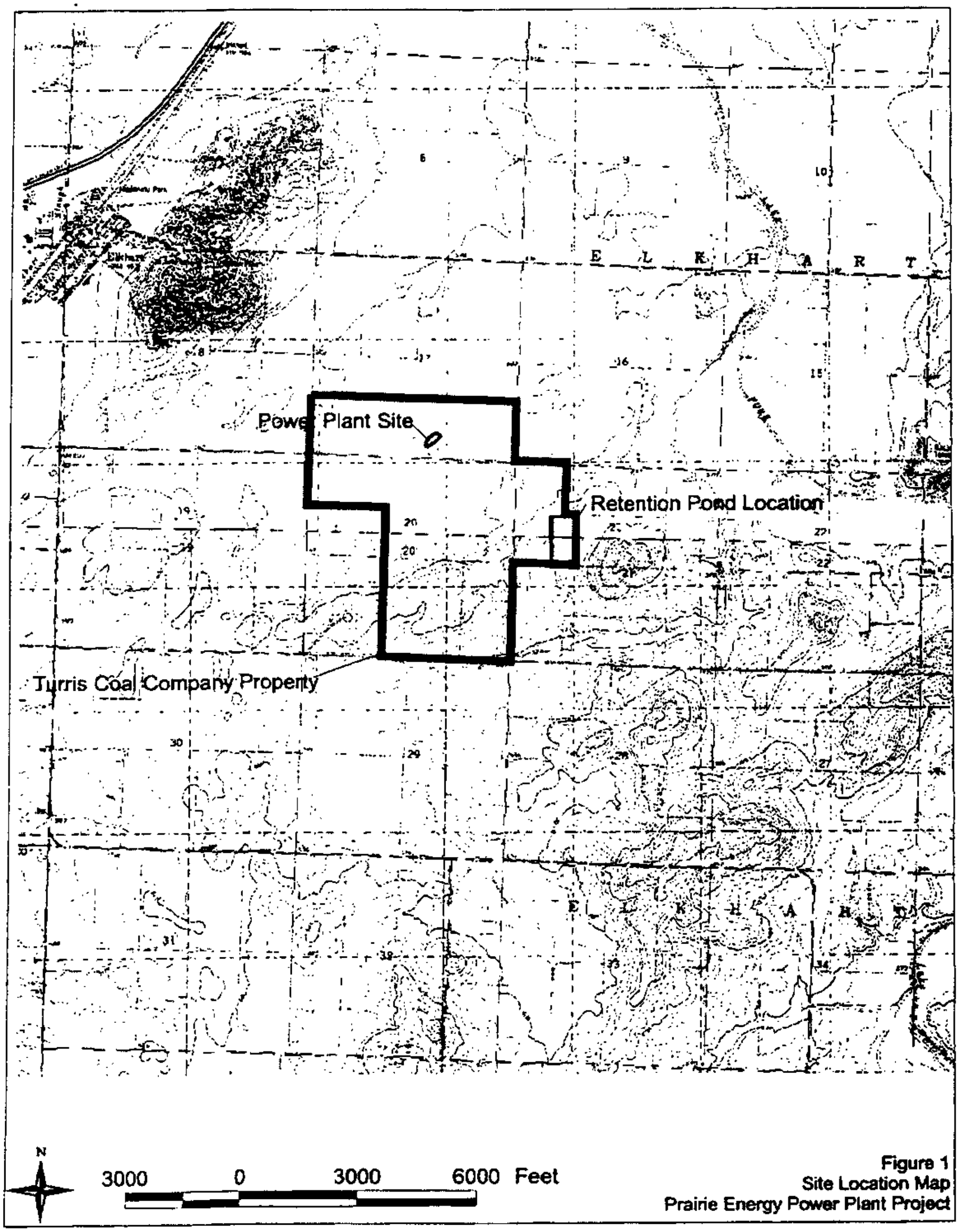

Figure 1
Site Location Map
Prairie Energy Power Plant Project

Illinois Historic Preservation Agency

1 Old State Capitol Plaza • Springfield, Illinois 62701-1507 • (217) 782-4836 • TTY (217) 524-7128

Logan County
Elkhart
Turris Mine
see also IHPA Log #0102200039HLO
Process Water Retention Pond at Turis Mine Power Plant site

Please refer to: IHPA LOG #0201230003HLO

January 23, 2002

Ms. L. Noelle Ferguson
Montgomery, Watson, Harza
Sears Tower
233 South Whacker Drive
Suite 900
Chicago, IL 60606-6392

Dear Ms. Ferguson:

Re: Results of Phase I Survey -

Acre(s): 50.00 Site(s): 0
Contractor: CRS - D. Halpin; ASSR received 11-26-01, Additional info received 12-26-01

Thank you for submitting the results of the archaeological reconnaissance. Our comments are required by Section 106 of the National Historic Preservation Act of 1966, as amended, and its implementing regulations, 36 CFR 800: "Protection of Historic Properties".

Our staff has reviewed the archaeological Phase I reconnaissance report performed for the project referenced above. The Phase I survey and assessment of the archaeological resources appear to be adequate. Accordingly, we have determined, based upon this report, that no significant historic, architectural, and archaeological resources are located in the project area.

Please submit a copy of this letter with your application to the state or federal agency from which you obtain any permit, license, grant, or other assistance. Please retain this letter in your files as evidence of compliance with Section 106 of the National Historic Preservation Act of 1966, as amended.

Sincerely,

Anne E. Haaker

Anne E. Haaker
Deputy State Historic
Preservation Officer

AEH:EGH:jrm

Cc: David Halpin, CRS

APPENDIX C

CONSULTATION LETTERS FOR WETLANDS AND FLOODPLAINS UNDER SECTION 404 OF THE CLEAN WATER ACT

ILLINOIS
DEPARTMENT OF
NATURAL RESOURCES
Office of Water Resources
524 South Second Street, Springfield 62701-1787 George H. Ryan, Governor ● Brent Manning, Director

February 28, 2001

SUBJECT: Cornbelt Energy Corporation
Proposed Coal-Fired Generating Plant
Turris Mine Site @ Elkhart

Mr. Douglas Mulvey
Harza Engineering Company
233 South Wacker Drive
Chicago, Illinois 60606-1787

Dear Mr. Mulvey:

Thank you for your February 15, 2001 inquiry concerning the need for Illinois Department of Natural Resources, Office of Water Resources (IDNR/OWR) authorization for the subject project. Since the project does not involve construction within a public body of water or within the floodway of a stream with a drainage area in excess of our ten square mile rural area jurisdictional limit, only our dam safety rules will be applicable.

From the information you provided, it appears that water is to be impounded in retention, freshwater, sediment, slurry and polishing ponds. As indicated in Section 3702.20 of the enclosed "Rules for Construction and Maintenance of Dams", embankments constructed for the purpose of storing water are defined as dams. IDNR/OWR permits are required for the construction, operation and maintenance of all Class I (high hazard) and Class II (significant hazard) dams and Class III (low hazard) dams meeting **any** of the following criteria:

- The drainage area of the dam is 6400 acres or more in a rural area or 640 acres or more in an urban area; or
- The dam is 25 feet or more in height (measured from the top of the dam to the lowest point at the downstream toe of the embankment) and the impounding capacity is greater than 15 acre feet; or
- The dam has an impounding capacity (calculated at the top of the dam) of 50 acre feet or more and the height of the dam is greater than 6 feet.

To enable our provisional hazard classification and determination of the need for IDNR/OWR permits, a preliminary design report for each dam will need to be submitted. Information to be included in a preliminary design report is listed on page 2 of the enclosed "Procedural Guidelines ..." booklet.

Mr. Douglas Mulvey
Page 2
February 28, 2001

Please feel free to contact Mike Diedrichsen of my staff at 217/782-3863 if you have any questions or comments.

Sincerely,

Dennis L. Kennedy, P.E.
Senior Water Resources Engineer

DLK:MLD:emm
Enclosures

DEPARTMENT OF THE ARMY
ROCK ISLAND DISTRICT, CORPS OF ENGINEERS
CLOCK TOWER BUILDING – P.O. BOX 2004
ROCK ISLAND, ILLINOIS 61204-2004

REPLY TO
ATTENTION OF

March 2, 2001

Operations Division

SUBJECT: CEMVR-OD-P-405410

Mr. Douglas Mulvey
HARZA Engineering Company
Sears Tower
233 South Wacker Drive
Chicago, Illinois 60606

Dear Mr. Mulvey:

Our office reviewed your application dated February 15, 2001, concerning the proposed construction of a generating facility in Section 17, Township 18 North, Range 3 West, Logan County, Illinois.

We determined your project as proposed does not require a Department of the Army (DA) Section 404 permit. Our office reviewed the information provided to us. No indication of discharge of dredged or fill material was found to occur in waters of the United States (including wetlands). Therefore, this determination resulted.

You are advised that this determination for your project is valid for five years from the date of this letter. If the project is not completed within this five-year period or your project plans change, you should contact our office for another determination.

Although an individual DA permit and individual IEPA 401 certification will not be required for the project, this does not eliminate the requirement that you must still acquire other applicable Federal, state, and local permits. If you have not already coordinated your project with the Illinois Department of Natural Resources - Office of Water Resources, please contact them at 217/782-3863 to determine if a floodplain development permit is required for your project.

-2-

Should you have any questions, please contact our Regulatory Branch by letter, or telephone me at 309/794-5369.

Sincerely,

Jeff Sniadach

Jeffrey W. Sniadach
Project Manager
Enforcement Section

Copies Furnished:

Mr. Bob Dalton
Illinois Department of Natural Resources
Lincoln Tower Plaza, 524 South Second Street
Springfield, Illinois 62701-1787

Mr. Bruce Yurdin
Manager, Bureau of Water Section #15
Watershed Management Section
Illinois Environmental Protection Agency
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

U.S. Army Corps of Engineers
Illinois Waterway Project Office
257 Grant Street
Peoria, Illinois 61603

MWH
MONTGOMERY WATSON HARZA

February 4, 2002

Mr. Jeffrey W. Sniadach, Project Manager
U.S. Army Corp of Engineers – Rock Island District
Clock Tower Building – P.O. Box 2004
Rock Island, Illinois 61204

Subject: Water Discharge Permit Requirement
Corn Belt Energy Corporation Generation Facility

Dear Mr. Sniadach:

MWH Americas, Inc (MWH) has been retained by Corn Belt Energy Corporation (CBE) of Bloomington, Illinois to provide permitting support for a coal-fired generation facility in Logan County, Illinois. I have exchanged previous correspondence with you pertaining to this project. Your correspondence number is identified as CEMVR-OD-P-405410.

As our plans have progressed I am making sure that we meet all regulatory permitting requirements. My question pertains to a process water pond located onsite that was constructed and is operated by the Turris Coal Company. The process pond has been identified on the Wetland Inventory Map shown in the attached figure. We plan to construct a discharge pipeline into this process pond. Will this action require a Nationwide permit?

If you have any questions, please contact me at (312) 831-3859 or email me at douglas.l.mulvey@mwhglobal.com. I look forward to your response. Thanks for your time and assistance.

Very truly yours,

Douglas Mulvey

Douglas L. Mulvey, P.E.
Senior Environmental Engineer

Enclosure: As noted

Sears Tower
250 South Wacker Drive, Suite 900
Chicago, Illinois
60606-6300

Tel: 312 831 3000
Fax: 312 831 3869

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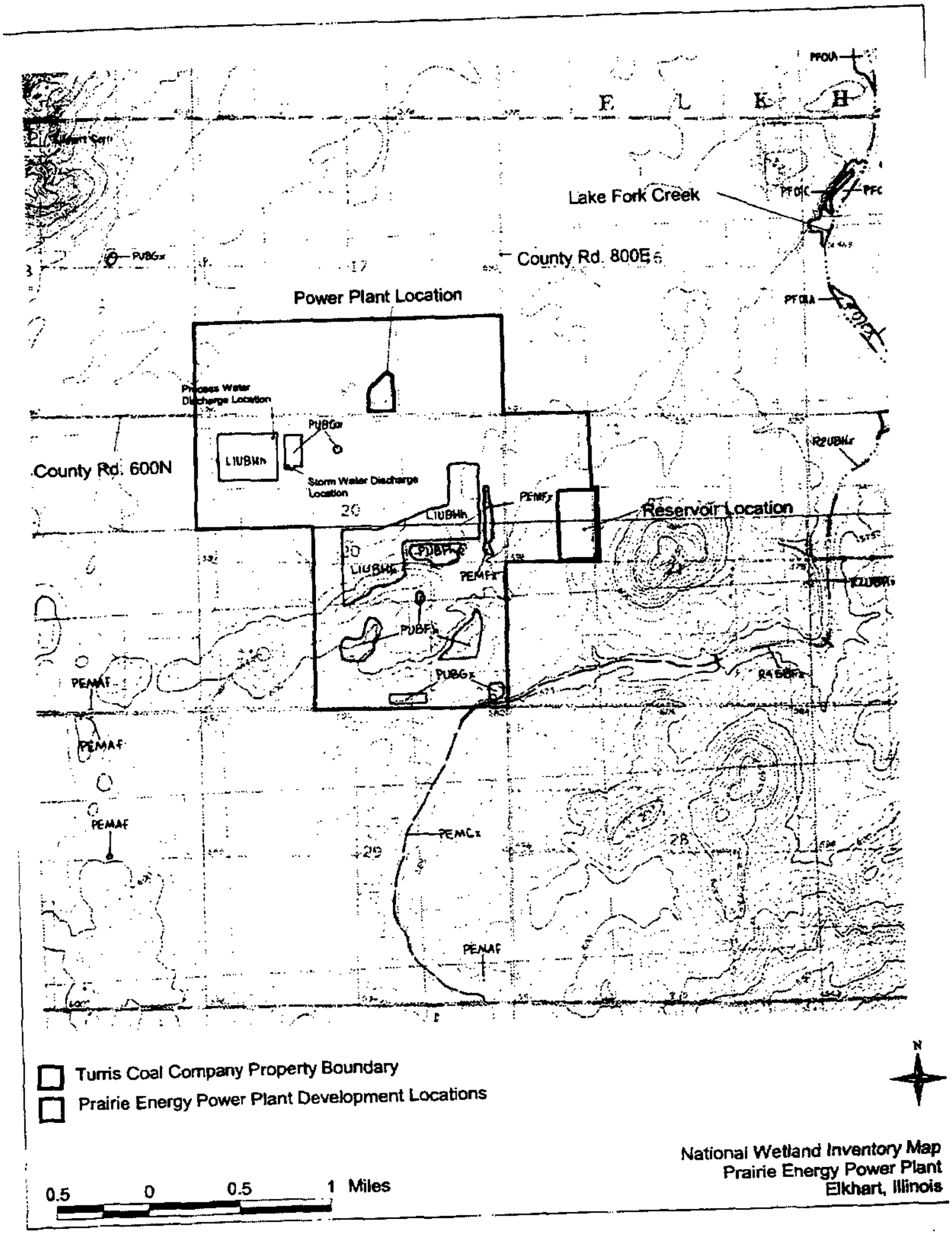
Lake Fork Creek
County Rd. 800E
Power Plant Location
Process Water Discharge Location
County Rd. 600N
Storm Water Discharge Location
Reservoir Location
Turris Coal Company Property Boundary
Prairie Energy Power Plant Development Locations
0.5
0
0.5
1 Miles
N
National Wetland Inventory Map
Prairie Energy Power Plant
Elkhart, Illinois

DEPARTMENT OF THE ARMY
ROCK ISLAND DISTRICT, CORPS OF ENGINEERS
CLOCK TOWER BUILDING – P.O. BOX 2004
ROCK ISLAND, ILLINOIS 61204-2004

REPLY TO
ATTENTION OF

February 15, 2002

Operations Division

SUBJECT: CEMVR-OD-P-422550

Mr. Douglas Mulvey
Montgomery, Watson,
Harza America's, Inc.
Sears Tower
233 South Wacker Drive, Suite 900
Chicago, Illinois 60606

Dear Mr. Mulvey:

Our office reviewed your letter dated February 6, 2002, concerning a request for a jurisdictional determination of a site, located in Section 20, Township 18 North, Range 3 West, Logan County, Illinois.

We determined your project site contains water of the United States not regulated under Section 404 of the Clean Water Act, and does not require a Department of the Army (DA) Section 404 permit. The decision regarding this action is based on information found in the administrative record which documents the District's decision-making process, the basis for the decision, and the final decision.

You are advised that this determination is valid for five years from the date of this letter unless new information warrants revision of it before the expiration date.

Although an individual DA permit and individual IEPA 401 certification will not be required for the project, this does not eliminate the requirement that you must still acquire other applicable Federal, state, and local permits. If you have not already coordinated your project with the Illinois Department of Natural Resources - Office of Water Resources, please contact them at 217/782-3863 to determine if a floodplain development permit is required for your project.

-2-

Should you have any questions, please contact our Regulatory Branch by letter, or telephone me at 309/794-5369.

Sincerely,

Jeff Sniadach

Jeffrey W. Sniadach
Project Manager
Enforcement Section

Copies Furnished:

Mr. Bob Dalton
Illinois Department of Natural Resources
Lincoln Tower Plaza, 524 South Second Street
Springfield, Illinois 62701-1787

Mr. Bruce Yurdin
Manager, Bureau of Water Section #15
Watershed Management Section
Illinois Environmental Protection Agency
1021 North Grand Avenue East
Post Office Box 19276
Springfield, Illinois 62794-9276

U.S. Army Corps of Engineers
Illinois Waterway Project Office
257 Grant Street
Peoria, Illinois 61603

APPENDIX D

STATE OF ILLINOIS PERMIT FOR CONSTRUCTION AND PSD APPROVAL

217/782-2113

CONSTRUCTION PERMIT - PSD APPROVAL - NSPS SOURCE

PERMITTEE

Corn Belt Energy Corporation
Prairie Energy Power Plant
Attn: Anthony Campbell, V.P. Electric Distribution
1502 Morrissey Drive
Bloomington, Illinois 61702-0816

Application No.:01070028 I.D. No.:107806AAC
Applicant's Designation: Date Received: July 10, 2001
Subject: Electricity Generation Facility
Date Issued: December 17, 2002
Location: Elkhart Mine Road, Mine-Mouth Project, Elkhart, Logan County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of a coal fired power plant with boiler, coal handling and storage, ash handling and storage, limestone handling and storage, cooling tower, and ancillary operations as described in the above referenced application and summarized in Attachment A. This Permit is granted based upon and subject to the findings and conditions that follow.

In conjunction with this permit, approval for the above activity is given with respect to the federal rules for Prevention of Significant Deterioration of Air Quality Regulations (PSD) for the above referenced equipment as described in the application, in that the Illinois Environmental Protection Agency (IEPA) finds that the application fulfills all applicable requirements of 40 CFR 52.21. This approval is issued pursuant to the Clean Air Act, as amended, 42 U.S.C. 7401 et seq., the Federal regulations promulgated thereunder at 40 CFR 52.21 for Prevention of Significant Deterioration of Air Quality (PSD), and a Delegation of Authority agreement between the United States Environmental Protection Agency (USEPA) and the Illinois EPA for the administration of the PSD Program. This approval becomes effective in accordance with the provisions of 40 CFR 124.15 and may be appealed in accordance with provisions of 40 CFR 124.19. This approval is also based upon and subject to the findings and conditions that follow:

Findings

1a. Corn Belt Energy Corporation (Corn Belt) has requested a permit for a coal fired power plant with a nominal capacity of 91 MW_e. The proposed boiler would be equipped with low NO_x burners, staged combustion, and a selective catalytic reduction (SCR) system; an electrostatic precipitator and wet scrubber with limestone injection. Ancillary operation would include coal handling and storage; ash handling and storage; limestone handling and storage; cooling tower; and other ancillary operations. The project is being pursued by Corn Belt in conjunction with a clean coal combustion grant from the United States Department of Energy (USDOE).

b. The boiler will have the ability to generate the steam for nominal 91 MW of electrical output. The boiler, which would have a rated capacity of about 900 million Btu/hour, will be fired on coal as its primary fuel with natural gas as startup fuel. The boiler would generally be designed for coal mined at the existing Elkhart mine which would nominally have 3.25 percent sulfur by weight and 10,450 Btu per pound higher heating value (HHV), which is equivalent to an uncontrolled sulfur dioxide emission rate of 6.2 pounds per million Btu heat input.

Page 2

2. The plant will be located on an approximately 95-acre site near Elkhart in Logan County. The site is in an area that is currently designated attainment for all criteria pollutants.

3. The proposed plant is a major source under PSD rules. The plant will have potential annual emissions of 584 tons of sulfur dioxide (SO_2), 477 tons of nitrogen oxides (NO_x), 79 tons of particulate matter (PM), 794 tons of carbon monoxide (CO), 17.9 tons of sulfuric acid mist (H_2SO_4) and 26.3 tons of volatile organic materials (VOM) as indicated in the application. The project is therefore subject to PSD review as a major new source for the above pollutants except VOM.

4. The proposed plant is a major source for emissions of hazardous air pollutants (HAP). The potential HAP emissions from the plant will be greater than 10 tons of an individual HAP, i.e., hydrogen chloride. Therefore, the plant is being subjected to review under Section 112(g) of the Clean Air Act.

5. After reviewing the materials submitted by Corn Belt, the Illinois EPA has determined that the project will (i) comply with applicable Board emission standards (ii) comply with applicable federal emission standards, (iii) utilize Best Available Control Technology (BACT) on emissions of NO_x, SO_2, PM/PM_{10}, and CO as required by PSD, and (iv) utilize Maximum Achievable Control Technology (MACT) for emissions of HAP as required by Section 112(g) of the Clean Air Act.

6. The proposed boiler is an affected unit under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act and are subject to certain control requirements and emissions monitoring requirements pursuant to 40 CFR Parts 72, 73 and 75. As affected units under the Acid Rain Program, Corn Belt must hold calendar year allowances for each ton of SO_2 that is emitted.

7. The air quality analysis submitted by Corn Belt and reviewed by the Illinois EPA shows that the proposed project will not cause violations of the ambient air quality standard for NO_x, SO_2, PM/PM_{10}, and CO. The air quality analysis shows compliance with the allowable increment levels established under the PSD regulations.

8. The Illinois EPA has determined that the proposed plant complies with all applicable Illinois Pollution Control Board Air Pollution Regulations; the federal Prevention of Significant Deterioration of Air Quality Regulations (PSD), 40 CFR 52.21; applicable federal New Source Performance Standards (NSPS) 40 CFR 60; and Section 112(g) of the Clean Air Act, and applicable federal National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63, Subpart B.

9. A copy of the application, the project summary prepared by the Illinois EPA and a draft of this permit were placed in the Elkhart Public Library, and the public was given notice and an opportunity to examine this material and to submit comments and to participate in a public hearing on this matter.

The Illinois EPA is issuing approval subject to the following conditions and consistent with the specifications and data included in the application. Any departure from the conditions of this approval or terms expressed in the application must receive prior written authorization of the Illinois EPA.

Page 3

Conditions

1. Standard conditions for issuance of construction permits, attached hereto and incorporated herein by reference, shall apply to this project, unless superseded by the following conditions.

2a. The boiler shall be operated and maintained with the following features to control emissions.

i. Good combustion practices including low NO_x burners, and staged combustion, or other secondary NO_x control technology.

ii. Selective catalytic reduction (SCR).

iii. Flue gas desulfurization (FGD).

iv. Electrostatic precipitator (ESP).

b. The emissions from the boiler shall not exceed the following limits except during startup, shutdown and malfunction as addressed by Condition 2(c).

i. PM - 0.02 lb/million Btu.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 10 and equipment operation.

ii. SO_2 - 0.15 lb/million Btu and, if emissions are 0.10 lb/million Btu or greater, 8 percent of the potential combustion concentration (92 percent reduction).

These limits shall apply on a 30 day rolling average with compliance determination using the compliance procedures set forth in the NSPS, 40 CFR 60.48a.

iii. NO_x - 0.120 lb/million Btu during the demonstration period and 0.10 lb/million Btu upon conclusion of the demonstration period, or such lower limit as set by the Illinois EPA following the Permittee's evaluation of NO_x emissions and the SCR system as required by Conditions 2(d) and 19. For this purpose, the demonstration period for the boiler shall be the first two years of operation or a period that extends six-months after the USDOE project demonstration ends, whichever is longer.

This limit shall apply on a 30-day rolling average using the compliance procedures of the NSPS, 40 CFR Part 60.48a.

iv. CO - 0.20 lb/million Btu.

This limit shall apply on a 30 day rolling average basis, with continuous monitoring conducted in accordance with Condition 12.

c. The Permittee shall use reasonable practices to minimize emissions during startup, shutdown and malfunction of the boiler as further addressed in Condition 7(b), including the following:

Page 4

i. Use of natural gas, during startup to heat the boiler prior to initiating firing of solid fuel;

ii. Operation of the boiler and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s); and

iii. Inspection, maintenance and repair of the boiler and associated air pollution control equipment in accordance with written maintenance procedures.

d. The Permittee shall evaluate NO_x emissions from the coal boiler to determine whether a lower NO_x emission limit (as low as 0.07 lb/mmBtu) may be reliably achieved while complying with other emission limits and without significant risk to equipment or personnel. This evaluation shall also examine whether there will be significant increase in ammonia emissions, as well as unreasonable increase in maintenance and repair needed for the boiler (see also Condition 19).

3a. i. Emissions of particulate matter from limestone handling and storage (excluding the raw limestone storage pile), and ash fly handling and storage shall be controlled with enclosures and aspiration to bag filters designed to emit no more than 0.01 grains/dry standard cubic foot (gr/dscf).

ii. Emissions of particulate matter from coal handling and storage (excluding storage piles) shall be controlled with enclosures and aspiration to bag filters designed to emit no more than 0.01 gr/dscf.

iii. Emissions of particulate matter from the limestone and coal storage piles shall be controlled by material quality and enclosure as practicable.

b. The Permittee shall follow good air pollution control practices to minimize nuisance fugitive dust from plant roads, parking areas, storage piles and other open areas of the plant. These practices shall provide for pavement on all regularly traveled roads and treatment (flushing, vacuuming, dust suppressant application, etc.) of paved and unpaved roads and areas that are routinely subject to vehicle traffic for very effective and effective control of dust, respectively (nominal 90 percent for paved roads and areas and 80 percent control for unpaved roads and areas).

c. The cooling tower for the steam-electric generating cycle shall be equipped, operated, and maintained with drift eliminators designed to limit the loss of water droplets from the cooling tower to not more than 0.001 percent of the circulating water flow.

4a. The boiler shall comply with one of the following requirements with respect to emissions of mercury:

i. An emission rate of 0.000004 lb/million Btu or emissions below the detection level of established emission test methodology;

ii. A removal efficiency of 90 percent achieved without injection of activated carbon or other similar material specifically used to control emissions of mercury, comparing the emissions and the mercury contained in the fuel supply;

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iii. Injection of powdered activated carbon or other similar material specifically used to control emissions of mercury in a manner that is designed to achieve the maximum practicable degree of mercury removal;

iv. Such other requirement for effective control of mercury emissions as may be established pursuant to Section 112(g) of the Clean Air Act in a revised PSD permit if the Permittee demonstrates that it cannot reasonably obtain performance guarantees or engineering confirmation for compliance with the above requirements; or

v. The requirements for control of mercury emissions established by USEPA pursuant to Section 112(d), once applicable rules are adopted by USEPA.

b. Compliance with the requirements in paragraphs (a)(i) and (ii) above shall be demonstrated by periodic testing related to mercury emissions and proper operation of the coal boiler consistent with other applicable requirements that apply to the coal boiler (e.g., requirements applicable to control of particulate matter and sulfur dioxide) as may be further developed or revised in the source's CAAPP Permit. Compliance with the requirements in paragraphs (a)(iii) and (iv) above shall be demonstrated by proper operation of the coal boiler and such other measures specified by the applicable permit. Compliance with the requirements in paragraph (a)(v) above shall apply as specified by the relevant rule.

c. This condition shall take effect 18 months after initial startup of the boiler. However, as related to paragraphs (a)(i) through (iv) above, the Permittee may at any time thereafter, upon written notice to the Illinois EPA, declare an interruption in compliance for a period of 18 months if needed for detailed evaluation of mercury emissions of the coal boiler or physical changes to the boiler as related to control of mercury emissions. As part of its notice for this period, the Permittee shall identify the activities that it intends to perform to evaluate mercury emissions or further enhance control for mercury emissions and specify the particular practices it will use during this period as good air pollution control practice to minimize emissions of mercury.

Condition 2,3 and 4 represents the application of the Best Available Control Technology as required by Section 165 of the Clean Air Act. Compliance with these limits will also assure that Maximum Achievable Control Technology is provided for emissions of hazardous air pollutants as required by Section 112(g) of the Clean Air Act.

5a. i. The boiler is subject to a New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60, Subparts A and Da. The Illinois EPA administers NSPS in Illinois on behalf of the USEPA under a delegation agreement.

ii. The emissions from the boiler shall not exceed the applicable limits pursuant to the NSPS. In particular, the NO_x emissions from the boiler system shall not exceed 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average, pursuant to 40 CFR 60.44a(d).

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iii. The particulate matter emissions from the boiler shall not exceed 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity pursuant to 40 CFR 60.42a(b).

b. i. The limestone handling and storage processes shall comply with the applicable requirements of the NSPS for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subparts A and OOO.

ii. A. Fugitive emissions of particulate matter from grinding mills, screens (except truck dumping), storage bins, and enclosed truck or railcar loading operations shall not exceed 10% opacity. (40 CFR 60.672(b) and (d))

B. Fugitive emissions of particulate matter from the crushers shall not exceed 10% opacity. (40 CFR 60.672(c))

C. Truck dumping of limestone into any screening operation, feed hopper, or crusher is exempt from the requirements of 40 CFR, Subpart OOO. (40 CFR 60.672(d))

c. The coal handling and storage processes shall comply with the applicable requirements of the NSPS for Coal Preparation Plants, 40 CFR 60, Subpart A and Y. Note: The NSPS are applicable because coal will be processed at the plant by crushing.

d. At all times, the Permittee shall maintain and operate emission units that are subject to NSPS, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

6a. The boiler is an affected unit under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act and is subject to certain control requirements and emissions monitoring requirements pursuant to 40 CFR Parts 72, 73 and 75. As an affected unit under the Acid Rain Program, the Permittee must also obtain an Acid Rain Permit for the boiler before commencing operation.

b. The boiler would qualify as an Electrical Generating Unit (EGU) for purposes of 35 IAC Part 217, Subpart W, the NO_x Trading Program for Electrical Generating Units. As an EGU, when this State of Illinois program becomes effective, the Permittee would have to hold NO_x allowances for the NO_x emissions of the boiler during each seasonal control period.

7a. Emissions from the boiler shall not exceed the limits in Table I. The limits in Table I are based upon the emission rates and the maximum firing rate specified in the permit application consistent with the air quality analysis submitted by the Permittee to comply with PSD. Compliance with hourly limits shall be determined with testing and monitoring as required by Conditions 10, 11, 12 and 13.

b. The Permittee shall operate the boiler and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions, by operating in accordance with detailed written operating procedures as it is safe to do so, which procedures at a minimum:

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i. Address startup, normal operation, and shutdown and malfunction events and provide for review of relevant operating parameters of the boiler systems during startup, shutdown and malfunction as necessary to make adjustments to reduce or eliminate any excess emissions.

ii. With respect to startup, address readily foreseeable startup scenarios, including so called "hot startups" when the operation of a boiler is only temporarily interrupted and provide for appropriate operating review of the operational condition of a boiler prior to initiating startup of the boiler.

iii. With respect to malfunction, identify and address likely malfunction events with specific programs of corrective actions and provide that upon occurrence of a malfunction that will result in emissions in excess of the applicable limits in Condition 2, the Permittee shall, as soon as practicable, repair the affected equipment, reduce the operating rate of the boiler or remove the boiler from service so that excess emissions cease.

Consistent with the above, if the Permittee has maintained and operated the boiler and air pollution control equipment so that malfunctions are infrequent, sudden, not caused by poor maintenance or careless operation, and in general are not reasonably preventable, the Permittee shall begin shutdown of the boiler within 90 minutes, unless the malfunction is expected to be repaired within 120 minutes or such shutdown could threaten the stability of the regional electrical power supply. In such case, shutdown of the system shall be undertaken when it is apparent that repair will not be accomplished within 120 minutes or shutdown will not endanger the regional power system. In no case shall shutdown of the boiler be delayed solely for the economic benefit of the Permittee.

Note: If the Permittee determines that the continuous emission monitoring system (CEMS) is inaccurately reporting excess emissions, the boiler may continue to operate provided the Permittee records the information it is relying upon to conclude that the boiler and associated emission control systems are functioning properly and the CEMS is reporting inaccurate data and the Permittee takes prompt action to resolve the accuracy of the CEMS.

c. The Permittee shall maintain the boiler and associated air pollution control equipment in accordance with good air pollution control practice to assure proper functioning of equipment and minimize malfunctions, including maintaining the boiler in accordance with written procedures developed for this purpose.

d. The Permittee shall review its operating and maintenance procedures as required above on a regular basis and revise them if needed consistent with good air pollution control practice based on actual operating experience and equipment performance. This review shall occur at least annually if not otherwise initiated by occurrence of a startup, shakedown, or malfunction event that is not adequately addressed by the existing plans or a specific request by the Illinois EPA for such review.

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8a. Emissions from emission units associated with the facility other than the boiler shall not exceed the limitations in Table II. These limits are based on data presented in the construction permit application and continuous operation (8,760 hours/year).

b. The emission of smoke or other particulate matter from the fuel and ash storage silos and other process emission units shall not have an opacity greater than 30 percent, pursuant to 35 IAC 212.123(a), except as allowed by 35 IAC 201.149, 212.123(b) or 212.124. Opacity measurements taken to demonstrate compliance with these provisions shall be based on a 6-minute average.

c. Visible emission of particulate matter associated with fuel storage pile, and the associated material handling operations shall comply with the provisions of 35 IAC 212.301.

9a. The boiler and associated equipment covered by this Permit may each be operated under this construction permit for a shakedown period of 365 days* after initial startup. During this period (365 days), notwithstanding Condition 2(b)(ii), the SO_2 reduction for the boiler need only comply with the reduction requirement of the NSPS, 40 CFR Part 60, Subpart Da.

* This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the shakedown of the plant.

b. For emission units that are subject to NSPS, the Permittee shall fulfill applicable notification and recordkeeping requirements of the NSPS, 40 CFR 60.7, 60.49a, and 60.676 including:

i. Written notification of commencement of construction, no later than 30 days after such date (40 CFR 60.7(a)(1));

ii. Written notification of anticipated date of initial startup, at least 30 days but not more than 60 days prior to such date (40 CFR 60.7(a)(2)); and

iii. Written notification of the actual date of initial startup, within 15 days after such date (40 CFR 60.7(a)(3)).

c. i. Under this permit, the boiler and associated equipment may be operated for a period that ends 180 days after the boiler first generates electricity to allow for equipment shakedown and emissions testing as required. This period may be extended by Illinois EPA upon request of the Permittee if additional time is needed to complete shakedown or perform emission testing of the boiler.

ii. Upon successful completion of emission testing of the boiler demonstrating compliance with applicable limitations, the Permittee may continue to operate the facility as allowed by Section 39.5(5) of the Environmental Protection Act.

iii. This condition supersedes Standard Condition 6.

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10a. i. For the boiler and other emission units that are subject to NSPS, within 60 days after achieving the maximum production rate at which the unit will be operated but not later than 180 days after initial startup of each such unit, the Permittee shall have performance tests conducted as follows below by an approved testing service at its expense under conditions that are representative of maximum emissions.

A. For the boiler, this period of time may be extended by the Illinois EPA for boiler for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of the boiler, provided that initial performance testing required by the NSPS, 40 CFR Part 60, Subpart Da has been completed for the boiler and the test report submitted to the Illinois EPA.

B. In addition for the boiler, notwithstanding the above provisions, testing for dioxin/furan emissions shall be conducted within three years of initial startup of the boiler, either in conjunction with other emission testing or by itself during representative operating conditions.

Note: This requirement is imposed for this facility because representative emission data for dioxin/furan is not available from a similarly designed and equipped boiler.

ii. In addition to the initial performance testing specified above, the Permittee shall perform emission tests as requested by the Illinois EPA for the boiler or other mission units within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA. The Illinois EPA may request these tests if, based on observations by field personnel, an emission unit or air pollution control systems are poorly maintained or operated so as to make compliance with permit limitations uncertain.

b. The following methods and procedures shall be used for emission testing:

i. For the boiler, the following USEPA methods and procedures shall be used for testing opacity and emissions of NO_x, CO, PM, VOM, SO_2, hydrogen chloride, hydrogen fluoride, sulfuric acid mist, dioxins/furans, and mercury and other metals, unless otherwise specified or approved by the Illinois EPA.

Opacity	Method 9
Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Particulate Matter[1]	Method 5, or Method 201, or 201A (40 CFR 51,Appendix M), with Method 19 as specified in 40 CFR 60.48a(b)
Condensable Particulate	Method 202
Nitrogen Oxides	Method 7, 7E or 19 as specified in 40 CFR 60.48a(d)

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Sulfur Dioxides	Method 6 or 19 as specified in 40 CFR 60.48a(c)
Carbon Monoxide	Method 10
Volatile Organic Material[2]	Method 18 or 25A
Hydrogen Chloride	Method 26
Hydrogen Fluoride	Method 26
Sulfuric Acid Mist	Method 8
Metals [3, 4]	Method 29
Dioxin/Furan	Method 23

Notes:

1 The Permittee may report all PM emissions measured by USEPA Method 5 as PM10, in which case separate testing using USEPA Method 201 or 201A need not be performed.

2 The Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.

3 For purposes of this permit, metals are defined as mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

4 During the initial emissions testing for metals, the Permittee shall also conduct measurements using established test methods for the principle forms of mercury present in the emissions, i.e., particle bound mercury, oxidized mercury and elemental mercury.

ii. The following USEPA methods and procedures shall be used for particulate matter and opacity measurements for the limestone handling and storage operations, as specified in 40 CFR 60.675:

Particulate Matter	Method 5 or 17
Opacity	Method 9

iii. The following USEPA methods and procedures shall be used for particulate matter and opacity measurements for solid fuel handling, as specified by 40 CFR 60.254:

Particulate matter - Method 5, the sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

Opacity - Method 9, opacity measurements shall be performed by a certified observer.

c. At least 60 days prior to the actual date of testing, a written test plan shall be submitted to the Illinois EPA for review. This plan shall describe the specific procedures for testing and shall include at a minimum:

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i. The person(s) who will be performing sampling and analysis and their experience with similar tests.

ii. The specific conditions, e.g., fuel supply, firing rate and control device operating rates, under which testing shall be performed including a discussion of why these conditions will be representative of maximum emissions and the means by which the operating parameters for the boiler system will be measured and recorded.

iii. The specific determinations of emissions that are intended to be made, including sampling and monitoring locations. As part of this plan, the Permittee may set forth a strategy for performing emission testing in the normal load range of the boiler.

iv. The test method(s) that will be used, with the specific analysis method if the method can be used with different analysis methods.

d. i. The Permittee shall notify the Illinois EPA prior to each of these tests to enable the Illinois EPA to observe these tests. Notification for the expected date of testing shall be submitted a minimum of 30 days* prior to the expected date, and shall be accompanied by a detailed plan describing the testing which will be performed. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days* prior to the actual date of the test.

* The Illinois EPA may at its discretion accept notifications with shorter advance notice provided that the Illinois EPA will not accept such notifications if it interferes with the Illinois EPA's ability to observe testing.

ii. This notification shall also identify the parties that will be performing testing and the set or sets of operating conditions (e.g., boiler load and fuels) under which testing will be performed.

e. Three copies of the Final Reports for these tests shall be forwarded to the Illinois EPA within 30 days after the test results are compiled and finalized. The Final Report from testing shall contain a minimum:

i. A summary of results;

ii. General information;

iii. Description of test method(s), including a description of sampling points, sampling train, analysis equipment, and test schedule;

iv. Detailed description of test conditions, including for the boiler:

A. Fuel consumption (in tons) of the unit being tested;

B. Composition of fuel (Refer to Condition 13(a) and (c);

C. Firing rate (million Btu/hr) of the unit being tested;

D. Control device operating rates, e.g., SCR reagent injection rate, supplementary ash/lime injection rate, etc.; and

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E. Turbine/Generator output rate (MWe).

v. Data and calculations, including copies of all raw data sheets and records of laboratory analysis, sample calculations, and data on equipment calibration.

11a. At a minimum, to confirm compliance with Condition 2(b)(i), the Permittee shall test particulate matter (PM) emissions from the boiler in accordance with Condition 10 at a regular interval that is no greater than 36 months, i.e., PM testing of the boiler at least once every 36 months. Notwithstanding the above, if the results of two of these PM tests consecutively for a boiler demonstrate PM emissions of 0.010 lb/million Btu or less, the maximum interval for testing of such boiler may be doubled, i.e., PM testing at least once every 72 months. Provided however, if a PM test for such a boiler then shows PM emissions above 0.010 lb/million Btu, the maximum interval between testing shall revert to 36 months until two consecutively tests again show PM emissions of 0.010 lb/million Btu or less.

b. Whenever PM testing for the boiler is performed as required above, testing for emissions of mercury shall also be performed in accordance with Condition 10.

12a. i. The Permittee shall install, certify, operate, calibrate, and maintain continuous opacity, SO_2, NO_x and CO monitoring systems and either an O_2 or CO_2 monitoring system on the coal boiler.

ii. The type, location, and operating procedures for the monitoring equipment for the boiler shall be approved by the Illinois EPA, prior to installation.

iii. The Permittee shall fulfill the applicable requirements for monitoring in the NSPS, 40 CFR 60.13, 60.47a, and 40 CFR 60 Appendix B, and the federal Acid Rain Program, 40 CFR Part 75.

b. In addition, when NO_x or SO_2 emission data are not obtained from a continuous monitoring system because of system breakdowns, repairs, calibration checks and zero span adjustments, emission data will be obtained by using standby monitoring systems, emission testing using USEPA Reference Methods (Method 7 or 7A for NO_x and Method 6 for SO_2), or other approved methods as necessary to provide emission data for a minimum of 75 percent of the operating hours in a steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days, pursuant to 40 CFR 60.47a(f) and (h).

13a. i. The Permittee shall sample and analyze the sulfur and heat content of the coal supplied to the boiler in accordance with USEPA Reference Method 19 (40 CFR 60, Appendix A, Method 19).

ii. This sampling and analysis shall include separate measurements for the sulfur and heat content of the coal supplied to the boiler.

b. The Permittee shall install, evaluate, operate, and maintain meters to measure and record consumption of coal by the boiler.

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c. The Permittee shall analyze representative sample of all coal supplies and any alternate fuel supplies that are components in the solid fuel supply to the boiler and the solid fuel supply itself for mercury and other metals and chlorine content, as follows:

i. Analysis shall be conducted in accordance with USEPA Reference Method or other method approved by USEPA.

ii. Sampling of the fuel supply to the boiler itself shall be conducted in conjunction with performance testing of the boiler.

iii. Testing of solid fuels shall also be conducted in conjunction with acceptance of coal from other than the Elkhart coal mine or an alternate fuel and on at least a biennial basis thereafter.

iv. The CAAPP permit may relax these requirements.

14a. i. The Permittee shall maintain a written fugitive dust control program describing the measures being implemented in accordance with Condition 3(b) to control fugitive dust at each area of the plant with the potential to generate significant quantities of fugitive dust. This program shall include estimated dust emissions control technique (e.g., water spray surfactant spray, water flushing, or sweeping); typical flow of water and additive concentration; normal frequency with which measures would be implemented; circumstances, e.g., recent precipitation, in which the measure would not be implemented; triggers for additional control, e.g. observation of 10 percent opacity; and calculated control efficiency.

ii. The program shall be accompanied by maps or diagrams indicating the location of areas at the plant with the potential to generate fugitive dust, with description (length, width, surface material, etc.) and volume and nature of expected traffic or other activity.

b. The Permittee shall submit a copy of this program to the Illinois EPA for review within 90 days of initial start up of the facility.

15a. The Permittee shall maintain the following records for the continuous monitoring systems required on the boiler required pursuant to Conditions 12 and 13(b):

i. Records of the output of the systems.

ii. Records of maintenance, calibration and operational activity associated with the monitoring systems.

b. The Permittee shall maintain the following records with respect to operation and maintenance of the boiler and associated control equipment:

i. An operating log for the boiler that at a minimum shall address:

A. Each startup of the boiler, including the nature of the startup, sequence and timing of major steps in the startup, any unusual occurrences during the startup, and any deviations from the established startup procedures, with explanation;

B. Each shutdown of the boiler including the nature and reason for the shutdown, sequence and timing of major steps in the shutdown, any unusual occurrences during the shutdown, and any deviations from the established shutdown procedures, with explanation; and

C. Each malfunction of the boiler system that significantly impairs emission performance, including the nature and duration of the event, sequence and timing of major steps in the malfunction, corrective actions taken, any deviations from the established procedures for such a malfunction, and preventative actions taken to address similar events.

ii. Inspection, maintenance and repair log(s) for the boiler system that at a minimum shall identify such activities that are performed as related to components that may effect emissions; the reason for such activities, i.e., whether planned or initiated due to a specific event or condition, and any failure to carry out the established maintenance procedures, with explanation.

iii. Copies of the steam charts and daily records of steam and electricity generation from the facility.

c. For the boiler, the Permittee shall maintain records of the following items related to fuel and emissions:

i. Records of SO_2 NO_x and PM emissions, as specified by 40 CFR 60 60.49a.

ii. The amount of fuel combusted in the boiler by type of fuel as specified in 40 CFR Part 60, Appendix A, Method 19.

iii. A. The sulfur content of solid fuel, lb sulfur/million Btu, supplied to each boiler, as determined pursuant to Condition 13(a); and

B. The sulfur content of solid fuel supplied to the boiler on a 30-day rolling average, determined from the above data.

iv. With respect to the SO_2 reduction based limit in Condition 2(b)(ii), for each 30 day averaging period, the SO_2 emissions in lb/million Btu and the required SO_2 emission rate as determined by applying the permissible emission fraction to the potential SO_2 emission rate of the solid fuel supply.

v. Records of the sampling and analysis of solid fuel supply to the boiler conducted in accordance with Condition 13 (c).

d. The Permittee shall keep inspection and maintenance logs for the PM filters associated with handling and storage of solid fuel and limestone.

16. All records, including written procedures and logs, required by this permit shall be kept at a readily accessible location at the plant and be available for inspection and copying by the Illinois EPA. These records shall also be retained for five years unless otherwise specified in a particular provision of this permit.

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17. The Permittee shall comply with applicable reporting requirements under the Acid Rain Program, with a single copy of such report sent to Illinois EPA, Division of Air Pollution Control, Compliance Section, upon request.

18a. The Permittee shall fulfill applicable reporting requirements in the NSPS, 40 CFR 60.7(c) and 60.49a, for the boiler. For this purpose, the semiannual reports shall be submitted no later than 30 days after the end of each six-month period. (40 CFR 60.49a(i))

b. In lieu of semiannual reports in Condition 18(a), the Permittee may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity. The electronic reports shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner/operator, indicating whether compliance with applicable emission standards and minimum data requirements of 40 CFR 60.49a were achieved during the reporting period. (40 CFR 60.49a(j))

c. Either as part of the periodic NSPS report or accompanying such report, the Permittee shall report to the Illinois EPA any and all opacity or emission measurements, which exceed the respective requirements set by this permit. These reports shall provide for each such incident, the pollutant emission rate, the date and duration of the incident, and whether it occurred during startup, malfunction, breakdown, or shutdown. If an incident occurred during malfunction or breakdown, all corrective actions taken shall also be reported. These reports shall also specify periods during which the continuous monitoring systems were not in operation.

d. The Permittee shall report any other exceedance or violation of the requirements of this permit, not addressed above, to the Illinois EPA within 90 days of the discovery of the event. This report shall include the date and time of the incident, a description of the incident, the level of emissions on an hourly basis, and magnitude of the incident, a description of the corrective measures taken and efforts made to prevent future occurrences.

e. The Permittee shall notify the Illinois EPA in writing at least 30 days prior to initial firing of any solid fuel other than coal or coal tailings in the boiler.

19a. The Permittee shall perform the evaluation of NO_x emissions from the boiler required by Condition 2(d) in accordance with a plan submitted to the Illinois EPA for review and comment. The initial plan shall be submitted to the Illinois EPA for review and comment no later than 60 days after initial start-up of the boiler.

b. The plan shall provide for systematic evaluation of changes, within the normal or feasible range of operation, in the following elements as related to the monitored NO_x emissions:

i. Boiler operating load and operating settings;

ii. Operating rate and settings of the SCR system;

iii. Flue gas temperature at SCR injection point(s);

iv. Combustion settings, including excess oxygen;

v. Amount of limestone added to the FGD system;

vi. Nitrogen content of the fuel supply;

vii. ESP parameters to assure surrogate compliance parameters;

viii. Opacity, particulate matter and sulfuric acid mist emissions; and

ix. Ammonia slip.

c. The Permittee shall promptly begin this evaluation after the boiler demonstrates compliance with the applicable emission limits as shown by emission testing and monitoring. At this time, the Permittee shall submit an update to the plan that describes its findings with respect to control of NO_x emissions during the shakedown of the boiler, which highlights possible areas of concern for the evaluation.

d. i. This evaluation shall be completed and a detailed written report submitted to the Illinois EPA within two years after the initial startup of the boiler.

ii. These deadlines may be extended for an additional year if the Permittee submits an interim report demonstrating the need for additional time to effectively evaluate NO_x emissions and propose an alternative limit or limits for NO_x emissions.

e. i. More stringent emission limits for NO_x emissions (but no more stringent than 0.07 lb/million Btu) shall be set as a result of this evaluation if the Illinois EPA finds that the boiler can consistently comply with such limits. Additional parameters or factors, e.g., the nitrogen content of the fuel supply, may be included in such limits to address particular modes of operation during which such limits may or may not be achievable.

ii. If the Permittee fails to complete the evaluation or submit the required report in a timely manner, the NO_x emission limit shall automatically revert to the lower limit identified above, i.e., 0.070 lb NO_x per million Btu.

20. Two copies of required reports and notifications concerning equipment operation, performance testing or continuous monitoring system shall be sent to:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance Section
P.O. Box 19276
Springfield, Illinois 62794-9276

<u>and</u> one copy, except the Annual Emission Report required by 35 IAC 254, shall be sent to the Illinois EPA's regional office at the following address unless otherwise indicated:

Illinois Environmental Protection Agency
Division of Air Pollution Control
5415 North University
Peoria, Illinois 61614

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21a. This permit shall become invalid as follows, pursuant to 40 CFR 52.21 (r)(2). This condition supersedes standard Condition 1.

This Permit shall become invalid if construction of the boiler is not commenced within 18 months after this permit becomes effective, if construction of this boiler is discontinued for a period of 18 months or more, or if construction of this boiler is not completed within a reasonable period of time.

b. For purposes of the above provisions, the definitions of "construction" and "commence" at 40 CFR 52.21 (b)(8) and (9) shall apply, which require that a source must enter into a binding agreement for on-site construction or begin actual on-site construction. (Also see the definition of "begin actual construction," 40 CFR 52.21 (b)(11)).

22a. This permit does not relieve the Permittee of the responsibility to comply with all local, state and federal Regulations which are part of the applicable Illinois State implementation plan, as well as all other applicable federal, state and local requirements.

b. In particular, this permit does not relieve the Permittee from the responsibility to carry out practices during the construction and operation of the plant, such as application of water or dust suppressant sprays to unpaved traffic areas, to minimize fugitive dust and prevent an air pollution nuisance from fugitive dust, as prohibited by 35 IAC 201.141.

If you have any questions on this permit, please call Shashi Shah at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:SRS:jar

cc: Region 2
USEPA Region V

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ATTACHMENT A

Table I

Boiler Emission Limitations

Pollutant	Pound/Million Btu[1]	Pounds/Hour[2]	Tons/Year
NO_x[3]	0.12/0.10[3]	109.0/90.8	477/398
CO	0.20	181.0	794
VOM	0.0065	6.0	26.3
SO_2	0.15	133.0	584
PM/PM10[4]	0.02	18.0	79
H_2SO_4	----	4.1	17.9
Mercury	----	----	0.02

Notes:

1 Compliance with the emission rates expressed in pounds per million Btu heat input shall be determined in accordance with the provisions in Condition 2(b).

2 Compliance with hourly emission limits shall be based on 24-hour block averages (NO_x, CO and SO_2) and 3-hour block average (VOM, PM/PM_{10} and H_2SO_4). Short-term emission rates do not apply during startup, shutdown or malfunction addressed by Condition 7(b).

3 The NO_x limits are phased, with an initial limit for the demonstration period, a lower limit thereafter, and provision for an even lower limit pursuant to the optimization program required by Conditions 2(d) and 19. For example, the NO_x emission limits in pound per million Btu are 0.12 for the demonstration period and 0.10 thereafter, with provision for a lower limit pursuant to the optimization program, which limit could be as low as 0.07.

4 All particulate matter (PM) measured by USEPA Method 5 shall be considered PM_{10} unless PM emissions are tested by USEPA Method 201 or 201A, as specified in 35 IAC 212.108(a). These PM limits do not address condensable particulate matter. (Condensable particulate was addressed in the particulate matter air quality impact analysis required by the PSD rules. For this purpose, the emission rates for condensable particulate matter were estimated to be equal to the emission rates for filterable particulate matter.)

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Table II

Particulate Matter (PM) Emission Limitations for Emission Units Other Than the Boiler

(Pounds per Hour and Tons per Year)

Emission Unit	Hourly	Annual
Cooling Tower	0.3	1.1
Limestone Crusher	0.002	0.01
Limestone Silo	0.3	1.1
Fly Ash Silo	0.4	1.9
Coal Transfer	0.2	0.8
Total	--	4.91

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